STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL

DPUC Investigation of Measures	**Docket No. 05-07-14PH02**
To Reduce Federally Mandated	**September 13, 2006**
Congestion Charges	

Connecticut Department of Public Utility Control Request for Proposals to reduce impact of FMCCs

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1 Introduction

1.1 Regulatory context

In June 2005, Connecticut policy makers enacted Public Act 05-01, *An Act Concerning Energy Independence* (the Act or EIA). The Act was created in response to: rising energy prices; the status of Connecticut's local generation capacity (much of which is relatively old, inefficient, and more polluting than new technologies); and a move by the ISO New England (ISO-NE) and the Federal Energy Regulatory Commission (FERC) to put in place locational capacity and reserve markets. All of these factors would expose Connecticut ratepayers to upward pressure on rates through increased Federally Mandated Congestion Charges (FMCCs). The EIA was intended, in part, to address these developments.

The Act authorizes the Connecticut Department of Public Utility Control (DPUC) to launch a competitive procurement process geared towards motivating new supply-side and demand-side resources in order to reduce the impact of FMCCs on Connecticut ratepayers. Subsection 12(c) of the Act requires the DPUC to develop and issue a request for proposals (RFP) to solicit the development of long-term projects to reduce FMCCs, with the local distribution companies serving as the counterparty to any such contracts.

According to Subsection 12(c) of the Act, the RFP would identify "measures that would reduce Federally Mandated Congestion Charges for the period commencing on May 1, 2006, and ending on December 31, 2010." The RFP may include but shall not be limited to: "(1) customer-side distributed resources; (2) grid-side distributed resources; (3) new generation facilities, including expanded or re-powered generation; and (4) contracts for a term of no more than fifteen years between a person and an electric distribution company for the purchase of electric capacity rights." Subsection 12(c) of the EIA further specifies that the RFP shall "encourage responses from a variety of resource types and encourage diversity in the fuel mix used in generation." Under subsection 12(g), the DPUC must give preference to proposals that result in the greatest aggregate reduction of FMCCs, make efficient use of existing sites and supply infrastructure, and serve the long-term interest of ratepayers.

Subsection 12(i) summarizes how the proposals received through the RFP should be evaluated and states that: "No contract shall be approved unless the department finds that approval of such contract would (1) result in the lowest reasonable cost of such products and services, (2) increase reliability, and (3) minimize federally mandated congestion charges to the state over the life of the contract."

1.2 Objectives of the RFP

The DPUC's primary objective with this RFP is to reduce the impact of FMCCs and other costs on Connecticut ratepayers by facilitating the development of new or incremental capacity[1], including generation capacity, demand-side response, and conservation projects. In launching this RFP process, the DPUC aims to encourage the development of such capacity sooner than

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[1] Please see Section 2.1 for the exact definition of eligible capacity.

might otherwise occur. A project's contribution to reducing Connecticut ratepayers' costs of power will be the main driver in the DPUC's evaluation methodology, which is discussed later in this document (see Section 5).

As part of this RFP process, the DPUC will be adhering to the approved principles and standards developed in Docket No. 05-07-20, "Development of a Process and Standards for Competitive Solicitation of Long-term projects to Reduce Federally Mandated Congestion Costs", issued on December 28, 2005. These principles and standards are provided in Appendix C to this document.

1.3 Brief overview

This section of the RFP provides a brief overview of what the DPUC is procuring, how the procurement process will work, and how winning Bidders will be compensated. This section should not be considered a replacement for the more detailed descriptions of the RFP that follow below.

This process will procure new or incremental generation capacity or demand-side capacity[2] electrically located in Connecticut[3] that is geared towards reducing the impact of FMCCs and other costs on Connecticut ratepayers, as measured by cost to Connecticut load. The RFP process will entail a Pre-bid Conference, a Qualifications Process to assess Bidders' technical and financial credentials, and a Financial Bid. Section 3.1 of the RFP outlines the timeline for the RFP and scheduled deadlines for the above milestones in the RFP process. Only qualifying, conforming bids will be accepted, and only non-substantive changes to the Contract will be accepted after the Pre-bid Conference. Note that the DPUC will carefully consider all suggested changes to the contract templates provided in writing and in oral communications through the end of the Pre-Bid Conference. Thus these Contracts will reflect considerable Bidder input.

The Connecticut electric distribution companies, The Connecticut Light & Power Company (CL&P) and The United Illuminating Company (UI), will serve as the contractual Counterparties to the Contracts, which may last as long as 15 years.[4] There will be one

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2 See Section 2.1 for the exact definition of eligible capacity.

3 For purposes of this RFP process, "electrically located in Connecticut" shall mean that the project will qualify to meet Connecticut's Local Sourcing Requirement in the Forward Capacity Market. In addition, as a requirement of this RFP, if a proposed project is a generation facility, the bidder for this proposed project will need to certify and document that the electrical output (energy) from the proposed project can reliably be delivered to points inside the state of Connecticut under various operating conditions, as discussed further in Section 5.4. For projects that are not qualified to participate in the Forward Capacity Market, the project must be located within the state of Connecticut.

4 Although the RFP does not require the Connecticut electric distribution companies to submit proposals in this RFP, the RFP does not preclude them from doing so. According to General Statutes of Connecticut § 16-243 M(c), any bids by the electric distribution companies must be on a fixed price basis, comparable to the bids submitted by third parties. The Department will judge bids from the electric distribution companies on the same basis as bids from third parties. Should one or both of the electric distribution companies decide to propose demand side response or other demand resource project(s) in this procurement process and that project(s) is selected, they will not be required to sign a contract. However, that electric distribution company would be bound by the exact same terms and requirements as any other independent third party as listed in the Contract, which would be enforced by regulatory order. Note that the Connecticut electric

counterparty per Contract awarded, initially based on the geographic location of the project vis-à-vis the service territories of the distribution companies.[5] Costs for the Contracts obtained in the procurement process will be allocated equally on a unitary (load ratio) basis to all CL&P and UI ratepayers, resulting in a consistent $/kWh charge.

There are three contract templates for this RFP: one for Generation, one for Demand Response, and one for Other Demand Resources (ODR) (includes Energy Efficiency, Conservation and Other Demand Resources (ODR), as defined herein). The Generation and Demand Response[6] Contracts are financial Contracts that will hedge the cost of this new or incremental capacity for Connecticut ratepayers. They are structured to be a financial Contract for Differences (CfD). The Generation and Demand Response Contracts will be settled against ISO-NE's Forward Capacity Market (FCM) and, at the election of the Bidder, against ISO-NE's Locational Forward Reserve Market (LFRM).[7] The Supplier will be required to participate in the ISO-NE Markets for which they qualify (both technically and economically), in order to receive payment. They will have to participate in a specified way in the applicable ISO-NE Markets as described further in the applicable Contract. They will also be required to meet certain performance obligations based on their technological specifications. However, it is important to note that ISO-NE requirements for market participation by non-generation resources (such as DR and ODR) take into consideration the size and characteristics of such projects and even allows for information from the Monitoring and Verification Report to be used in lieu of metered data (should the project not possess a metering system).

The Generation and Demand Response Contracts will have a two-way payment structure. Bidders will submit a financial bid in $/kW per annum terms, referred to as the Annual Contract Price. This price, along with market clearing prices in the FCM and the LFRM[8] (at the option of the Bidder), will be used to settle the monthly payments between the Contract

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distribution companies have to submit competitive bids that meet the requirements of the RFP to be considered.

5 If a project is electrically interconnected with one electric distribution company but located geographically within the service territory of the other distribution company, its contract will be administered by the latter electric distribution company. Note that the allocation of projects will be assessed to ensure that the anticipated annual payment stream by the electric distribution companies is balanced on an 80% (CL&P)/20% (UI) basis. Contracts for winning projects may be re-allocated to approximate such a balance at the discretion of the Department at the time of bid selection. Any remaining true-ups needed between the distribution companies will occur in the semi-annual FMCCs settlement proceedings at the DPUC.

6 We are mirroring ISO-NE's rules regarding eligibility for the FCM. As long as resources are eligible as per ISO-NE rules to participate in the FCM, they will be eligible for a Generation or Demand Response Contract (based on project technology); the Contract Quantity in these contracts will be determined on ISO-NE's ratings of such projects based on their technology, even in the case that ISO-NE derates some or any of these technologies. If ISO-NE Market Rules change such that a resource is completely ineligible to participate in the FCM prior to Contract execution, the DPUC will consider allowing it to switch to an ODR Contract (at the Financial Bid previously submitted to the DPUC).

7 A bidder may propose to settle against the LFRM for only part of the Contract Term (or for portions of the years, i.e., for the summer period or winter period only), but must indicate this intent in the Financial Bid and specify the precise settlement period.

8 More specifically, if the LFRM option is selected, the Annual Contract Price and the market clearing price in the LFRM referenced in the contract will be those net of the FCM payments, rather than the unadjusted market clearing prices from the FRA.

Counterparties. The bid will represent the level of capacity payments the project needs in order to be developed and operated, taking into account expected profits from Energy Markets, Renewable Energy Credits[9], and other potential income streams, where applicable. If the Annual Contract Price is above the actual market clearing price in the FCM and, if elected, the LFRM, the Buyer will true-up the Supplier, by paying the difference between the Annual Contract Price and market clearing prices in the Forward Capacity Auction (FCA) and the Forward Reserve Auction (FRA)[10], thus ensuring a stable stream of revenue to the Supplier.[11] If the Annual Contract Price is lower than actual market clearing prices, the Supplier will make payments to the Buyer, based on the difference between the Annual Contract Price and the market clearing prices. [12]

The Capacity Contracts will also have a one-way Call Option that Bidders may elect. The Call Option will provide a secure, fixed revenue stream for projects in the form of a supplemental capacity payment, in lieu of certain portion of profits from the energy market. In exchange for this fixed, guaranteed additional revenue stream, the Bidder will pay to Connecticut ratepayers (through the Buyer) the product of its Contract Quantity under the Call Option and difference between the hourly Locational Marginal Price ("LMP") in ISO-NE Day-Ahead Market and the specified Strike Price for each hour over the Term of the Contract when the LMP in ISO-NE's Day Ahead Energy Market rises above the specified Strike Price. Through this payment mechanism from the Supplier to the Buyer, this Call Option will be an effective cap on LMPs and therefore hedge the costs of energy for Connecticut ratepayers. If the Bidder elects to bid this Call Option, he will need to supply the following as part of his Financial Bid (i) the Call Option Contract Quantity (which can be any amount less than or equal to the Contract Quantity for the Annual Contract Price), (ii) a bid for the supplemental capacity payment on the Call Option in $/kW per annum terms, (iii) the Strike Price (in $/MWh terms), and (iv) an index for changing that Strike Price over the Term of the Contract. Should the project be selected as a winning bid, and the Call Option selected by the DPUC[13], the Supplier would be contractually committed for the Call Option for the specified Call Option Contract Quantity over the Term of the Contract.

The third Contract will be used for those projects that ISO-NE refers to broadly as Other Demand Resources (ODR). The ODR Contract allows for direct payment with no settlement against a market index. Should ISO-NE allow these ODR assets to participate in the FCM in the future, the contract terms will automatically convert to the type of market settlement described for the Generation and Demand Response Contracts. Please refer to the ODR Contract for

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9 Note that other ratepayer funding, such as that from the Connecticut Clean Energy Fund or the Conservation & Load Management Fund, will be considered as a cost in the Bid Evaluation process, as described in Section 5.

10 Please refer to footnote 8 above.

11 Note that monthly payments will be adjusted for any "penalties" that the Supplier incurs from ISO-NE. Specifically, the Buyer will reduce payment to the Supplier for not performing to the specifications of ISO-NE, as is more fully described in the Contracts. The Supplier may face additional performance-related liquidated damages from the Buyer on an annual basis if there is degradation in stipulated technical performance criteria during the Term of Contract, as is more fully described in the Contracts.

12 Please refer to footnote 8 above.

13 The DPUC will have the right to accept the proposed bid for capacity with or without the Call Option.

further details. As stated above, such market settlement would take into consideration the small size and more limited administrative abilities of ODR resources.

Consistent with Section 12(i) of the Act, which describes the factors that the DPUC must consider for approving the Contracts, the evaluation of bids will be largely based on economic projections of the project's anticipated impact on energy, capacity, and forward reserve costs to Connecticut load under a variety of different scenarios. A uniform discount rate (9.8%)[14] will be used for all projects for the purpose of the Economic Analysis, thus the DPUC will be incorporating the issue of project execution risk as a separate factor, in order to reflect the project-specific risk. Furthermore, additional criteria from the EIA will also be assessed during the Bid Evaluation Process using a point system (see discussion of "Other Factors" in Section 5.5.2 of the RFP). Lastly, the potential risk of accumulated market power by Bidder(s) will also be rigorously analyzed, as described in Section 5.[15]

1.4 Caveats

The DPUC reserves the right to withdraw or modify this RFP at any time, to negotiate with all qualified Bidders to resolve technical or contractual specifications, and to accept or reject any or all proposals received as a result of this RFP. This RFP does not commit the DPUC to award a Contract or to be responsible or liable in any manner for risks, costs, expenses incurred by any Bidder in the preparation of a proposal in response to this RFP, or any revision of such a

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14 This discount rate is the average of UI's and CL&P's current allowed Return on Equity, which reflects the market risk that the distribution companies are compensated for, and the implied risk that their ratepayers incur in order to secure reliable supply. The current allowed ROE for CL&P is 9.85%, which was set in the December 17, 2003 Decision in Docket No. 03-07-02. The current allowed ROE for UI is 9.75% and was established in the January 27, 2006 Decision in Docket No. 05-06-04.

15 The potential concern of market power will be closely monitored throughout the RFP process, and in the Financial Bids submitted by Bidders. It is important to note that the long term Contracts being awarded through this RFP are effective safeguards against market power in the wholesale market because the contracts remove most of the economic motivation for strategic behavior. Furthermore, by requiring that projects participate in the ISO-NE Markets to the fullest extent possible, the Contracts incorporate strong preventive mechanisms against the exercise of market power. Suppliers under the Generation Contract are required to bid the contracted capacity into the energy market as a result of their FCM commitments. The Contracts also require that these Suppliers bid competitively in the energy market, and any indication that they have abused their market power during the Term of the Contract will require the Supplier to bid in at stipulated bid prices (short run marginal costs) for the following 12 months. In addition, the Peak Energy Rents (PER) mechanism in the FCM requires generators who had been awarded a capacity contract in the FCM to refund some portion of their energy revenues to load serving entities (for the benefit of ratepayers) if the LMP in the energy market rises above a certain level. If a Bidder elects the Call Option and that project is selected by the DPUC with the Call Option, this element will also guard against market power, as this Supplier will be motivated to bid competitively so as to reduce its exposure to payouts under the Call Option. In summary, the economics of the Contracts, the obligations of the Supplier to participate in ISO-NE Markets (which brings with it the requirements of the PER, and the safeguards afforded by ongoing monitoring by the Market Monitor), and the Call Option election all serve to inhibit the exercise of market power. The combination of these contractual provisions along with the DPUC's assessment of market power will protect Connecticut ratepayers from any potential market power abuses in this RFP and during the Term of the Contracts. The DPUC will also be monitoring the actual procurement process to ensure that it is a competitive one. Part of this assessment will entail comparing Financial Bids to expected market outcomes based on the baseline modeling in order to gauge the relative competitiveness of the Financial Bids vis-à-vis market expectations.

proposal. The DPUC will ensure that all Bidders are treated fairly in this procurement process and that no Bidder will have access to information that other Bidders do not have access to, as is highlighted in the Code of Conduct, which is attached as Appendix L.

2 Description of products being procured

2.1 Eligible resources

As per the terms of Section 12(c) of the EIA, projects eligible for this RFP shall include "(1) customer-side distributed resources, (2) grid-side distributed resources, [and] (3) new generation facilities, including expanded or repowered generation." The DPUC is interpreting this clause as broadly as possible to include, but not be limited to: new generation facilities; additional investments to existing generation facilities that increase the total capacity that can be considered electrically located in Connecticut; conservation; other demand-side resources; and energy efficiency projects.[16, 17] Distributed Generation (DG) projects are considered eligible to participate in this RFP process. However, given the number of other programs available to DG projects under the EIA, projects will have to choose to participate in this process *or* to take advantage of other programs for DG offered in the EIA. If they choose to participate in this procurement process, DG projects can select the Contract that is most appropriate to their economic and technical characteristics.[18] The DPUC will consider proposed bids from all technologies and fuels, although fuel-switching projects are not eligible in this procurement process. In addition to the specifications listed above, all projects - except those projects as defined in the ODR Contract - must meet the technical requirements needed to participate in the FCM and other ISO-NE Markets (as applicable), as required by the Contract, in order to be considered eligible.

Existing resources will not be considered to be eligible under this procurement process. Bids must be for new or incremental capacity, subject to the requirements below. Existing capacity will be defined at the site level by assets and associated capacity ratings listed as "active" in the most recent ISO-NE CELT Report (2006).[19] Any assets not listed in the 2006 CELT Report will be considered as new capacity. Incremental capacity will therefore be defined as the difference between the new (increased) summer demonstrated capacity and the Summer Seasonal Claimed Capacity listed in the 2006 CELT Report.

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16 All non-generation projects, including conservation, energy efficiency, and demand response projects, will need to have all of the following characteristics to qualify as a capacity resource in this RFP process: (i) the capacity reduction must be measurable, quantifiable, and verifiable; and (ii) the project must document its start and end dates as well as its impact on regional load. Staggered start dates with increasing amounts of Capacity are permissible, and should be reflected in the Contract Quantity listed for each year in the Financial Bid. These Contract Quantities will then be reflected in the Contract for selected projects. Likewise, the aggregation of smaller projects at multiple locations and of different ODR technologies is also permissible and should be clearly explained in the project description template. However, Bidders must commit to specific Contract Quantities, project types, and project locations in the Financial Bid Template.

17 Municipal entities can submit project proposals and such projects will be considered if they include (i) incremental or new capacity from a new or incremental generation resource, as defined above, or (ii) a demand response, conservation, or energy efficiency project located in CL&P's or UI's service territories.

18 Proposal submission forms and requirements, such as security deposits, for DG projects will be based on the type of Contract selected by the Bidder.

19 ISO-NE publishes a report annually on Capacity, Energy, Loads, and Transmission. This report can be found at: http://www.iso-ne.com/trans/celt/report/index.html.

Assets listed in the 2006 CELT Report as "deactivated" will be considered as new capacity contingent on the refurbishment or replacement of the de-activated unit within the first three years of the Contract (with a summer demonstrated capacity rating at a level equal to or greater than 90% of the de-activated unit's summer demonstrated capacity, based on the unit's summer demonstrated capacity in the last CELT report, in which that unit was designated as "active").

The DPUC will also accept bids from refurbished or re-powered capacity as long as all of the following conditions are met:

- the aggregate summer demonstrated capacity on the facility site increases;
- the original unit being refurbished or re-powered is at least 30 years old;
- new investment at a pre-existing site electrically located in the state of Connecticut results in an increase in output greater than 20% of the site's demonstrated summer capacity, or 40 MW, whichever is greater; and,
- Bidders will be required to commit in the Financial Bid Template to the number of years that they will maintain a net increase in capacity at the site, a commitment which shall be included in the Contract and which will be legally binding.

The DPUC will accept bids for up to the entire capacity of the refurbished or re-powered units (based on summer demonstrated capacity) as long as all of the conditions listed above are met. However, Bidders should note that the DPUC will take the following approach regarding such projects in the Bid Evaluation process: the DPUC will consider the full cost of the amount of capacity that is bid into the RFP process, regardless if it is the incremental capacity or the entire unit capacity, while the benefits analysis will reflect the DPUC's going-forward assumption that there will be no asset retirements or refurbishments in Connecticut until 2010. Thus, the project's estimated benefits in the Bid Evaluation process will only reflect the value of the incremental change in capacity over the near term.

If Bidders cannot meet the requirements listed above, the DPUC will accept bids for the incremental increase in capacity such that this incremental capacity will be considered as "New Capacity" in the FCM. Specifically, the Bidder must demonstrate that the incremental output increase is equal to or greater than 2% of the project's Summer Seasonal Claimed Capability.

For conservation, energy efficiency, and demand response projects, existing capacity will be defined as any project enrolled (as of December 1, 2006) in an ISO-NE or DPUC program. Therefore, new capacity is any resource that is not enrolled (as of December 1, 2006) in an ISO-NE or DPUC program. Additionally, the DPUC will consider bids from projects that are currently enrolled in such programs, but whose arrangements for funding will expire prior to the proposed start date of their Contract, as reflected by the associated term of their Financial Bid. In other words, Bidders could submit a bid for the years that their existing projects are not going to be supported by an ISO-NE or DPUC program.

2.2 Types of resources required

On August 25, 2006, the DPUC publicly issued its revised *Report on the Electricity Sector Investment Needs of Connecticut* (the "August 25, 2006 Needs Assessment"), which is part of Docket No. 05-07-14PH02. Subsequently to Written Exceptions filed with the DPUC on September 1, 2006, the August 25, 2006 Needs Assessment was revised to take into account expected reduction in emergency generation resources once the SWCT Gap RFP contracts expire in May 2008. The revised August 25, 2006 Needs Assessment details the DPUC's views on incremental capacity needs in the state based on a forecast of demand and procurement requirements in ISO-NE product markets under different supply conditions.[20] The DPUC strongly urges potential Bidders in this RFP process to review the document in its entirety.

In the revised August 25, 2006 Needs Assessment, the DPUC explained that incremental capacity needs for Connecticut differ according to which of the ISO-NE product markets drive the FMCCs: Energy, FCM, and LFRM. The DPUC concluded that needs for LFRM will drive Connecticut's short-term needs, while the capacity market (namely, the FCM) will drive long term needs in Connecticut. The needs in the LFRM have to be met by supply resources that can provide energy within a short timeframe, whether they are online resources running below their maximum capability or quick-start offline resources (including dispatchable demand response). The needs in FCM are driven by the level of peak demand as it corresponds to installed capacity. And, the needs in the Energy Market are driven by price considerations, rather than sufficiency in the quantity of energy.

As such, the DPUC analyzed each of these product markets to identify investment needs in Connecticut over the next 15 years under four different scenarios. The four scenarios represent a potential combination of supply-demand over the longer term, based on different load growth outlooks coupled with different new entry and retirement profiles (driven by varying economic considerations and environmental costs). The ultimate intent of the scenarios was to capture a number of plausible future states of the world, taking into account the economic response of the markets. The four scenarios include:

(i) Scenario 1: a "Modified Market Outcome with Reference Demand Case" scenario, which incorporates generic new entry (proxy capacity) entering the market in 2010

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[20] The DPUC engaged London Economics International LLC (referred to herein as LEI or London Economics) as a consultant to provide independent detailed economic support to the DPUC in assessing the needs for additional capacity investment in Connecticut to reduce FMCCs, to help design an RFP to solicit projects, and to evaluate resulting bids to supply the capacity. While all reasonable care has been taken to ensure that this analysis is complete, regulatory regimes and power markets are highly dynamic, and thus certain recent developments may or may not have been included in the analysis. This analysis is not intended to be a complete and exhaustive analysis of all issues affecting the New England market. Further, there can be substantial variation between assumptions and market outcomes analyzed by various consulting organizations specializing in competitive power markets and investments in such markets. Interested persons should note that this analysis does not obviate the need to make further appropriate inquiries as to the accuracy of the information included herein, and to undertake their own analysis and due diligence. The results provided or opinions put forth in this analysis do not constitute a promise or guarantee as to the occurrence of any future events, nor is the information contained herein meant for private market investment purposes.

based on projected market dynamics. This scenario uses ISO's reference (50/50) demand forecast;

(ii) Scenario 2: a "Delayed Entry with Reference Demand Case" scenario has generic new entry starts entering the market after a delay of a few years (2013) due to regulatory and market uncertainties. ISO's reference (50/50) demand forecast is used in this case, as in Scenario 1 above;

(iii) Scenario 3: an "Accelerated Entry with Low Economic Growth Demand" scenario uses ISO's low economic case demand forecast. In this scenario, generic new entry starts augmenting existing supply beginning in 2009, in pursuit of a first mover advantage and in anticipation of robust demand growth;

(iv) Scenario 4: a "Delayed Entry with High Economic Growth Demand and Tighter Environmental Restrictions" scenario uses ISO's low economic case demand forecast; and. Generic new entry starts supplementing existing supply beginning in 2014, reflecting a delayed market response due to uncertainty and siting delays. In addition, tighter environmental restrictions are incorporated, raising market costs in certain areas of New England and motivating additional retirements over time.

Each of the four scenarios incorporated differing perspectives and timing for proxy new generation additions, as well as economic retirements (environmental regulations were also incorporated and therefore were also considered in the market forecast and the entry and retirement decisions). The proxy new generation consists of generic capacity resources that are added exclusively to satisfy expected needs in the energy, FCM, and LFRM markets, subject to the conditions underlying each scenario. The new proxy peakers are assumed to bid their entire capacity into the LFRM and the FCM, and participate in the energy market when economics warrant. The new proxy baseload capacity is ineligible for the LFRM but does bid its entire capacity into the FCM and participate in the energy market. For the purpose of the revised August 25, 2006 Needs Assessment, the generic capacity serves primarily as "placeholders" for real projects and therefore are not counted in the measure of investment needs.

The revised August 25, 2006 Needs Assessment first analyzed the incremental capacity requirements of each product market separately, and then on a joint basis, to account for incremental supply resources in one product market which can satisfy needs in other product markets. For the LFRM, the investment needs are based on the deficit between Locational Forward Reserve Requirements (LFRRs) for Southwest Connecticut (SWCT) and Greater Connecticut zones and the total of qualified LFRM resources in each these Reserve Zone (without the proxy capacity). In order to investigate the investment needs in the FCM, the gross deficit was calculated between existing supply (without the proxy capacity) and the minimum procurement target for Connecticut, which would be the Local Sourcing Requirement (LSR). Based on existing resources and the range of demand forecasts, SWCT is never a Capacity Zone and therefore does not have a specific need for incremental capacity purposes of the FCM that is distinct from the state-wide investment need.

Figure 1 illustrates the overall investment needs for Connecticut state-wide, based on the short-term needs in the LFRM and the longer term needs in the FCM. The results in Figure 1 indicate that Connecticut has the immediate need for 629 MW of incremental new capacity in 2007,[21] and specifically capacity that would qualify for the LFRM. The variability of the incremental capacity need across scenarios in the initial years is a function of the year-on-year changes modeled in qualifying capacity, primarily due to changes in the Forward Reserve Heat Rate that defines the strike price in the LFRM. Nonetheless, the variation is not substantial because of the static nature of the LFRRs, which are the zonal procurement targets set by ISO in the LFRM. The incremental capacity needs in the early years of this assessment would be best satisfied by quick start capacity, such as peaking generation and dispatchable demand response.

In the longer term, the incremental capacity needs of the FCM dominate the investment needs for Connecticut. The incremental capacity required for the FCM is a function of the LSR for Connecticut, which in turn is driven by demand projections. Therefore, there is a wider deviation in longer term investment needs for the state across the four scenarios. It is important to note that there is no specific type of resource required in the long term, so long as it can satisfy the Local Sourcing Requirements (LSRs) in the FCM.

Figure 1. Summary of cumulative investment needs for Greater Connecticut assuming optimization of complementarity between product markets (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Greater Connecticut															
Scenario 1	629	629	625	626	626	623	624	623	623	624	624	813	997	1,201	1,409
Scenario 2	629	626	626	624	623	625	625	625	625	624	624	813	997	1,201	1,409
Scenario 3	629	625	623	629	625	629	624	624	624	625	621	624	625	625	629
Scenario 4	629	631	631	631	633	693	716	723	812	1,059	1,311	1,608	1,900	2,188	2,483

= Investment needs driven by LFRM
= Investment needs driven by FCM

By 2018, the state-wide investment need for incremental capacity ranges from 624 MW (under scenario 3) to as much as 1,608 MW (under scenario 4) and by 2021, the range for new capacity is even further expanded (from 629 MW to as much as 2,483 MW).[22] Investment needs diverge across scenarios in the long term because of the different ISO demand forecasts (reference case versus high economic and low economic cases).

Figure 2 highlights the incremental capacity needs for the Southwest Connecticut (SWCT) sub-area. In contrast to the needs estimated for Connecticut as a whole, the investment needs in Southwest Connecticut are centered on the capacity deficit for the LFRR. In 2007, the Southwest Connecticut investment need for incremental capacity starts at 158 MW and declines to 58 MW in 2008 reflecting a decline of 100 MW in the LFRR. Due to the static procurement targets, i.e. LFRR, the investment needs are static over the modeling horizon and similar across scenarios.

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21 629 MW is the immediate investment need identified. The Department may wish to procure more or less than this capacity, depending on the Financial Bids received.

22 It is important to note that Scenario 1 and Scenario 2 essentially have the same investment needs because they have effectively the same demand forecast and same existing resource base. However the two scenarios differ in the amount and particularly timing of generic new entry, which will produce different market prices and cost to load expectations (for the Bid Evaluation).

While the market needs for SWCT are not generally distinct from the statewide needs, it is important to note that there may be other valid reasons for emphasizing new build in SWCT. ISO-NE continues to be concerned with potential transmission security and reliability problems in load pockets like SWCT. In addition, ISO-NE notes in the draft RSP 2006 that it may be more efficient for new generation projects to site in SWCT, closer to load and effectively utilizing new transmission infrastructure after completion of Phase I and II of the SWCT transmission project.[23] Substantial generation additions in other parts of Connecticut may not easily be accommodated by existing transmission infrastructure and has the potential to create the need for incremental transmission investments.

Figure 2. Summary of cumulative investment needs for Southwest Connecticut (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Southwest Connecticut															
Scenario 1	158	58	56	58	58	54	55	54	54	55	55	55	56	56	58
Scenario 2	158	58	58	55	54	56	56	56	56	55	55	55	56	56	58
Scenario 3	158	56	54	60	57	60	56	56	56	57	53	55	56	56	58
Scenario 4	158	58	58	58	59	73	81	83	85	79	79	75	56	58	58

= Investment needs are driven by LFRM
= Investment needs are driven by FCM

In addition to the analysis summarized above, the DPUC urges bidders to monitor information issued by ISO-NE's Planning Advisory Committing and Markets Committee, which includes economic assessments of the New England Market and asset siting information. This information is available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html and at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/index.html.

Note that, while these analyses are intended to provide Bidders with information that should help guide their bid development, the estimates summarized above, and described in detail in the revised August 25, 2006 Needs Assessment, do not obligate the DPUC to procure the exact quantity of capacity identified in the Needs Assessment. Indeed, the DPUC will select projects in the RFP based on the Financial Bids received and the projected benefits and costs of the proposed projects.

2.3 Contract length

The maximum allowed contract length under the EIA is 15 years. The DPUC has not set a minimum or a target contract length. The DPUC encourages Bidders to propose a contract

23 ISO-NE staff note, however, that significant amounts of undergrounding of the transmission system does limit, or at least complicate, interconnection access for new generation. The revised August 25, 2006 Needs Assessment describes some of these issues, as well as some of the other preliminary conclusions of the ISO-NE draft RSP 2006 in more detail.

length, subject to the limits under the EIA that they believe is most suitable for their project. Bidders must specify their preferred contract length and their anticipated contract start date (based on the Commercial Operation Date) in their proposals.[24] If a project is awarded a contract in this RFP, the Commercial Operation Date and proposed Term will be reflected in the terms and conditions of the Contract.

Proposals will be evaluated on a Net Present Value (NPV) basis in 2006 dollars, discounting anticipated project costs and benefits from when the project is expected to go on-line until the contract termination date back to the present day. The DPUC is using this approach in order to compare projects on a common basis in terms of their projected impact on reducing FMCCs and other costs, regardless of contract length. The DPUC will use the same discount rate of 9.8% (see footnote 14 for an explanation of how this discount rate was selected) for all projects. Note that this approach will inherently benefit those projects that come on-line more quickly. This is intentional, and represents the uncertainty premium that the DPUC is incorporating for projects with a Commercial Operation Date that is far into the future. Project-specific execution risks, which will take into account the relative risk of each individual project, will be examined after the NPV analysis establishes the expected net benefits of each submitted project in 2006 dollar terms.

2.4 Pricing

Suppliers will be required to submit a bid for capacity payments in $/kW per annum terms, referred to as the Annual Contract Price. In general, this capacity payment will be settled against market clearing prices in the Forward Capacity Market, and, if desired by the Supplier, against market clearing prices in the Locational Forward Reserve Market.[25] Note that market clearing prices in the LFRM will be net of the FCM prices, which are automatically paid to any winning bidders in the LFRM. The RFP will refer to this as the "net LFRM price" for clarity. Projects bidding under the ODR Contract will use a different pricing structure to the extent that they do not qualify to participate in the FCM, which is discussed below.

Separate bids must be submitted for the FCM and the LFRM, if a Supplier chooses to net against both markets. The Annual Contract Price will represent the level of total capacity payments the project needs to be developed and operated, taking into account expected profits from other markets, such as the Energy Market, and other income sources (such as the sale of Renewable Energy Credits), where applicable. The Contract will have a two-way payment structure. If the Annual Contract Price for the capacity market is above the FCA's Auction Clearing Price for the applicable Supply Period, the Buyer will true-up the Supplier by paying the Supplier the difference between the Annual Contract Price and the Auction Clearing Price from the applicable FCA. On the other hand, if the Annual Contract Price is below the FCA Auction Clearing Price for the applicable Supply Period, the Supplier will pay the Buyer the difference. The same approach will be used for the LFRM. An illustrative diagram is provided in Figure 3

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24 As stated previously, staggered Commercial Operation Dates are permissible as long as the Financial Bid clearly reflects the amount of capacity that will be available each year.

25 Note that the Supplier may elect to settle against the Locational Forward Reserve Market for only a subset of the years or seasons within the year(s), though this must be indicated in the Financial Bid.

to show how this pricing mechanism will work. In this example, the bidder has elected to settle against both the FCM and the LFRM.

Note that the Annual Contract Price will be divided into twelve (12) equal installments to derive the Monthly Contract Prices, which will facilitate the monthly settlement process. Auction Clearing Prices in the Reconfiguration Auctions will not be considered for settlement for the purposes of this Contract.

Figure 3. Indicative illustration of pricing mechanism

		YEAR 1		YEAR 2		YEAR 3
Monthly Contract Price ($/kW)						
FCA	$	8.00	$	8.50	$	9.00
Net LFRM	$	5.00	$	6.00	$	5.50
Auction Clearing Price ($/kW)						
FCA	$	7.00	$	8.00	$	9.00
Net LFRM	$	6.00	$	6.00	$	6.00
Monthly Payment Amounts ($/kW)						
(positive indicates payment to Supplier; negative indicates payment to Bu						
FCA	$	1.00	$	0.50	$	-
Net LFRM	$	(1.00)	$	-	$	(0.50)
Net	**$**	**-**	**$**	**0.50**	**$**	**(0.50)**

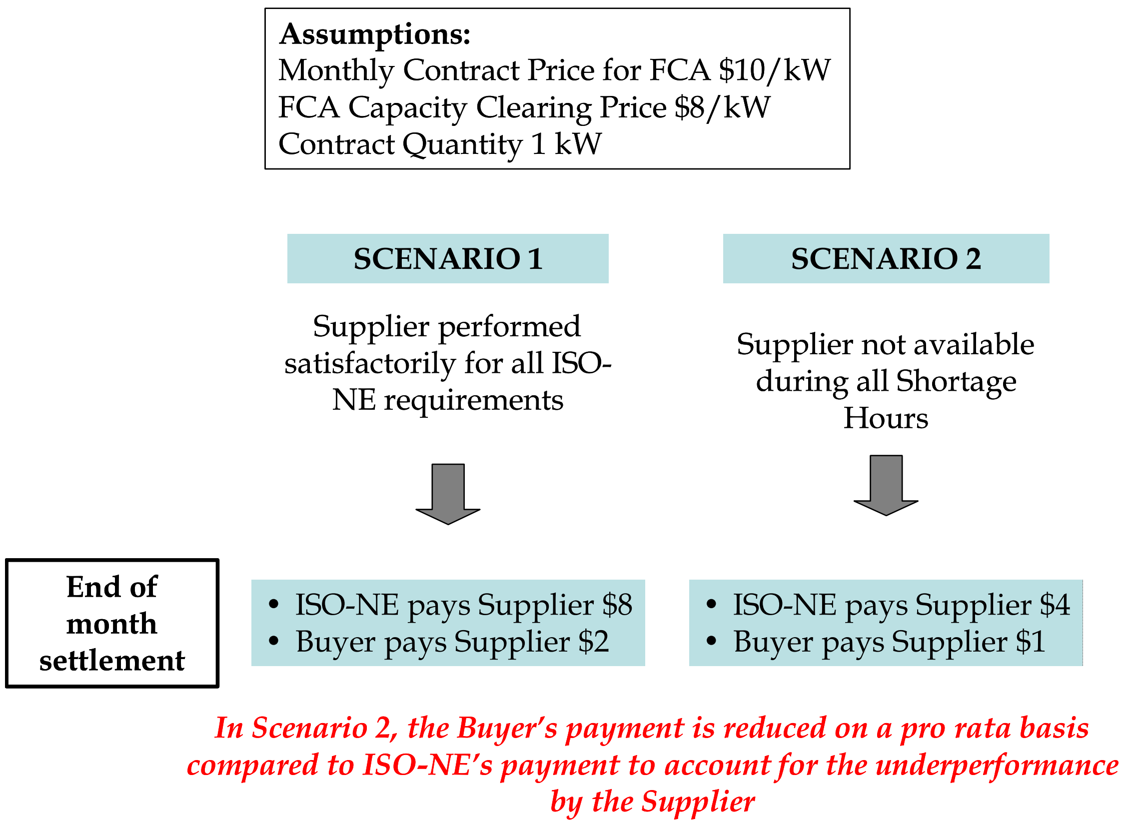
Note that Net LFRM refers to the fact that the capacity clearing price from the FCA has been netted already from the Auction Clearing Price in the LFRM.

There will also be true-ups in the monthly settlement process for performance payments (for availability) under and consistent with ISO-NE Market Rules. Thus, the Monthly Payment Amount will be adjusted on a pro-rata basis, in relation to the ISO-NE payments, as illustrated in Figure 4 below, and specified in more detail in the Contracts.

In addition, as specified in the Generation Contract, there will be performance requirements imposed on the Supplier related to annual Target Availability and thermal efficiency (Heat Rate) tests over the Term of the Contract. The Monthly Payment Amount may be further reduced by specified liquidated damages in the Generation Contract, if performance under these requirements is below threshold levels. Similarly, for the Demand Response Contract, to the extent that ISO-NE's FCM penalties do not account for overall availability, the Demand Response Contract will monitor the annual Performance Rates of these resources and the Supplier's payment may be adjusted from time to time to account for underperformance vis-à-vis the warranted Performance Rate(s).

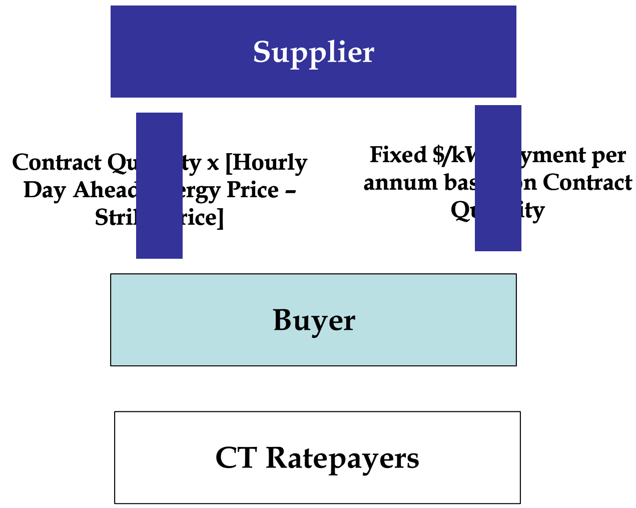
For the transition period, December 1, 2006 through May 31, 2010, the annual Transitional Capacity Payment, as approved by FERC, will be used as the indicative FCA Auction Clearing Prices for settlement purposes for any projects that come on-line and begin commercial operation before the Commitment Period of the first FCA. Adjustments will be made for availability of capacity per the guidelines adopted by ISO-NE with respect to the Transition Period.

Figure 4. Illustrative example of how ISO-NE penalties will be accounted for in monthly settlement (example using settlement against FCM only)



The RFP will also give Bidders the opportunity to enter into a Call Option for up to the Contract Quantity for supplemental capacity payments. The Call Option will be settled against the hourly prices from ISO-NE's Day Ahead Energy Market. It will require that a Supplier pay the Buyer the product of (i) the Call Option Contract Quantity and (ii) the positive difference, if any, between (a) the hourly Locational Marginal Price in the ISO-NE Day Ahead Energy Market and (b) the Strike Price. If a Bidder elects a Call Option, he will provide the (i) supplemental capacity payment being sought, (ii) the Call Option Contract Quantity, (iii) the Strike Price, and (iv) the index for changing the Strike Price over the Term of the Contract as part of his Financial Bid. The Call Option is illustrated in Figure 5 below. Prospective bidders and the electric distribution companies (as counterparties) may submit comments on the design of the Call Option (as described in the Contracts) to the DPUC by October 6, 2006.

Figure 5. Overview of the Call Option for supplemental capacity payments



For projects that do not qualify at the time of Contract execution for the FCM, the ODR Contract allows for a direct payment stream (the Monthly Contract Price) in exchange for the capacity (and associated performance requirements). However, should the project start to qualify for the FCM mid-contract, the payment terms would then adjust to settle against the FCM, as is described in more detail in the ODR Contract. The capacity of the ODR projects (the ODR Demand Reduction Value) will also be grossed up to account for the avoided peak demand transmission and distribution losses and, if applicable, the ICAP Reserve Margin, based on the appropriate ISO-NE regulations for ODR assets.

3 RFP process

3.1 Anticipated schedule

The anticipated schedule of the RFP process is as follows:

- Final RFP and contract templates issued: September 15, 2006
- Bidder registration deadline: September 29, 2006
- Final written comments on contract due from potential contract counterparties: October 6, 2006 at 5 PM EPT (Eastern Prevailing Time)[26]
- Date and location of Pre-bid Conference: October 10, 2006 at the Legislative Office Building in Hartford, CT[27]
- Date Qualification submissions due: November 13, 2006 by 5 pm EPT
- Date Financial Bid submissions due: December 13, 2006 by 5 pm EPT
- Date by which DPUC issues Decision on selection process and announces winning Bidders: No later than April 23, 2007
- Date by which Contracts must be executed and filed by the distribution companies with the DPUC for approval (within fifteen Calendar Days after Bid Selections): No later than May 8, 2007
- Date by which DPUC issues Decision approving Contract(s) (within six months of Contract execution): No later than November 8, 2007.

The DPUC reserves the right to revise, suspend, or terminate this schedule at its sole discretion. In that event, the DPUC will inform all registered Bidders as far in advance as reasonably possible, and the information will be posted on the RFP website (www.connecticut2006RFP.com).

3.2 Information dissemination, code of conduct, and communications

The RFP and Contracts, and all related documentation, are available for download from the RFP website. The website address is: www.connecticut2006RFP.com. Bidders are responsible for

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26 Such comments should be submitted to the RFP coordinator and a copy should also be sent to the DPUC (as described for the Bidder Registration in Section 3.4).

27 A confirmation of the location and time of the Pre-Bid conference will be posted on the RFP website, www.connecticut2006RFP.com. Attendees are requested to pre-register with the RFP Coordinator by 5 pm EPT on October 5, 2006.

accessing the RFP website for updated schedules and possible amendments to the RFP, Contracts, or the procurement process.

The DPUC has designated London Economics as the RFP Coordinator. Their job will be to manage the procurement process. London Economics will work in close coordination with the DPUC in this role. The RFP Coordinator will be accessible via email at RFPCoordinator@Connecticut2006RFP.com. All questions and requests about the RFP must be directed to the RFP Coordinator in writing at the above email address. For urgent or purely administrative questions, the RFP Coordinator can also be contacted through the fax and/or phone number provided below.

RFP Coordinator
London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
Email: RFPCoordinator@Connecticut2006RFP.com
Phone: 617-933-7225
Fax: 617-933-7201

The DPUC will ensure that all Bidders have access to the same information from the DPUC and that no Bidder will have selective or otherwise preferential access to information from the DPUC through this RFP process, as is highlighted in the DPUC's Code of Conduct for this procurement process attached to this document as Appendix L.

All questions and comments submitted by Bidders, as well as the DPUC's responses to such questions, will be posted on the RFP website. The official response to questions submitted by Bidders is the written response posted on the RFP website. The DPUC's objective in posting these questions, comments, and responses is to ensure that all Bidders are treated in a fair and equal fashion and have equal access to information that may be relevant to their proposals. The DPUC will not identify the name of the party submitting questions. The DPUC is under no obligation to provide additional information, but it may do so at its sole discretion.

3.3 Confidentiality

The DPUC, with the support of its staff and consultants, will be managing the RFP process. All original bid information marked as confidential and filed under seal (as described below) and approved as confidential by the Department will remain confidential until six months after the DPUC has issued a Decision approving the Contracts. As described further below, some types of bid information and some portion of the Contracts may remain confidential even after the Decision approving the Contracts.

The electricity distribution companies that will serve as Counterparties to these Contracts and will not be a part of the project selection committee and will not have access to any information on a preferential basis to other third parties until project selection has been complete. The distribution companies serving as Counterparties, and specifically Reviewing Parties representing the distribution companies, will also be obliged to sign a Confidentiality/Non-Disclosure Agreement (see the FERC Model Protective Order under Appendix K) before receiving Contracts for the selected projects.

The DPUC will take reasonable precautions and use reasonable efforts to protect any proprietary and confidential information contained in the proposals, provided that such information is clearly identified. Bidders should file information that they seek to treat as confidential under seal along with a motion for a protective order requesting that the DPUC grant confidential treatment for the specific portions of the proposal that they deem to be proprietary and confidential. The information filed under seal should clearly be marked "confidential" on the top of each page. The motion should indicate the basis in federal or state law for keeping the information confidential. Such information may be made available to the consultants of the DPUC for the purpose of evaluating the proposals, but those consultants will be required to observe the same care with respect to disclosure as the DPUC.

It is anticipated that, once winning project(s) are selected, the DPUC will release a redacted summary description of the project for the selected project(s), an analysis describing the results of the Bid Evaluation and supporting information for the selection of winning bids, as well as the results of the market power analysis. Actual Annual Contract Prices as submitted on the Financial Bid Template by the Supplier will be released publicly six months after the Contract(s) have been approved by the DPUC. Since this procurement process is ultimately being funded by the ratepayers of CL&P and UI and, in the interest of transparency and accountability, the DPUC would like to release as much information as possible into the public sphere once the Contracts have been approved. With this objective in mind, the DPUC requests that Bidders present views on what information in the Contract (including information that the Supplier may provide to the Buyer from time-to-time over the Term of the Contract) must imperatively be kept confidential even after Contract approval.[28] Bidders should provide support for this position by way of references to federal and state law, specifically including references to the Connecticut Freedom of Information Act.

3.4 Bidder registration

Bidder registration is required in order to participate in the RFP. The deadline for bidder registration is September 29, 2006 (the Bidder Registration Date). The Bidder Registration Form, which is attached to this document as Appendix D, should be completed and submitted to the RFP Coordinator by the Bidder Registration Date via email to RFPCoordinator@Connecticut2006RFP.com. There are no fees required to register to participate in this RFP process.

A second copy of the Bidder Registration Form should also be sent to the DPUC care of Louise Rickard via email *and* via certified mail or courier.

Louise Rickard
DPUC
10 Franklin Square
New Britain, CT 06051

[28] Stakeholders in the procurement process have stated that in addition to the bids submitted in this RFP, all data that must be reported to the Buyer and to the DPUC during the Term of the Contract, such as cost and technology-specific data, should be protected as confidential. The DPUC has reflected this recommendation in the revised contract templates it plans to release with the RFP. In addition, other aspects of the Financial Bid, such as detailed technical specifications, may also be granted confidentiality, although the process outlined in Section 3.3 must be followed to obtain such protection.

Phone: 860-827-1553
Email: louise.rickard@po.state.ct.us

3.5 Pre-bid conference

The Pre-bid Conference will occur on October 10, 2006 at the Legislative Office Building in Hartford, CT. Attendance is not mandatory, but all interested parties and potential Bidders are encouraged to attend. Attendees will be requested to pre-register with the RFP Coordinator by October 5, 2006, by sending an email to RFPCoordinator@Connecituct2006RFP.com. The purpose of the Pre-bid Conference is to allow potential Bidders the opportunity to ask questions and seek clarification about the RFP process. To make the meeting as productive as possible, potential Bidders are encouraged to submit any questions in writing to the RFP Coordinator via email to RFPCoordinator@Connecticut2006RFP.com at least three business days in advance of the Pre-Bid Conference (by 5 PM EPT, October 4, 2006). A transcript of the meeting, as well as any distributed materials, will be made available on the RFP website.

3.6 Qualification submission

The deadline for qualifications submissions is November 13, 2006 by 5 pm EPT, and all documents[29] should be submitted to the RFP Coordinator by email at RFPCoordinator@Connectictut2006RFP.com. In addition, Bidders should email *and* deliver a hard copy (via certified mail, or courier) of their qualification submission to:

Louise Rickard
DPUC
10 Franklin Square
New Britain, CT 06051
Phone: 860-827-1553
Email: louise.rickard@po.state.ct.us

The Qualifications Phase of this RFP process is intended to ensure that all Bidders that submit Financial Bids are competent and capable of fully performing the details of their bid, both in terms of their financial and their technical capabilities. Thus, in the Qualifications Phase, the DPUC will be assessing the Bidder Team's financial and technical wherewithal. Submissions to the qualifications process will not constitute a requirement to submit a Financial Bid. However, qualifications submissions must be complete, and must meet minimum eligibility requirements (discussed in Section 4) in order for a Bidder to qualify to submit a Financial Bid. Note that the DPUC has the right to solicit additional information as part of the qualification process in order to develop a comprehensive understanding of a Bidder's qualifications, but it is under no obligation to do so. Therefore, all qualifications submissions need to be as complete as possible. The DPUC will notify all Bidders as to the status of their qualifications submission at least two weeks prior to the due date of Financial Bids.

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[29] Confidential treatment of any material in the Qualifications package can be sought using the procedures outlined in Section 3.3.

Given the complexity of the Bid Evaluation Process (which is discussed in Section 5), the DPUC also plans to obtain technical information about each project and each project's anticipated financing at this stage. This will allow the DPUC to gain a clearer understanding of the potential pool of proposed projects before the DPUC receives the Financial Bids.

Documents that must be submitted as part of the Qualifications process by November 13, 2006:

Five documents must be submitted as part of the qualification submission process, templates for all of which are attached as appendices to this document:

- Appendix E: Introduction to Bidder Team
- Appendix F: Minimum Technical Requirements
- Appendix G: Financial Questionnaire
- Appendix H: Project Description Questionnaire
- Appendix I: Anticipated Project Financing Questionnaire

All information contained in the Appendices listed above, except for Appendix E: Introduction to Bidder Team and Appendix G: Financial Questionnaire, can be revised or updated until the deadline for Financial Bid submission (see Section 3.7), provided that Bidders have substantive and compelling reasons for such changes, and have submitted notice of such changes prior to the Financial Bid submission deadline, along with documentation for such changes to the satisfaction of the DPUC.

3.7 Financial Bid submission

The deadline for Financial Bid submission is December 13, 2006 by 5 pm EPT. Financial Bids must be submitted to the RFP Coordinator via email to RFPCoordinator@Connecticut2006RFP.com. In addition, Bidders should email *and* deliver a hard copy (via certified mail, or courier) of their Financial Bid to:

Louise Rickard
DPUC
10 Franklin Square
New Britain, CT 06051
Phone: 860-827-1553
Email: louise.rickard@po.state.ct.us

The Financial Bid Template, attached here as Appendix J, must be completed in its entirety. Financial Bids must meet the specifications within the Financial Bid Template in order to be considered. Non-conforming bids will be rejected.

A refundable Project Security Deposit must be submitted along with the Financial Bid. The Project Security Deposit will be set at:

- $25/kW for all generation projects that are larger than 5.0 MW;
- $10/kW for generation projects that are smaller than 5.0 MW, and for all demand response projects; or
- $5/kW for Other Demand Resources (such as demand side management and energy efficiency projects).

The Project Security Deposit can be provided in the form of US currency or an irrevocable and unconditional standby Letter of Credit issued by a financial institution having a minimum credit rating of A- (S&P)/A3 (Moody's)/A (Fitch). Deposits provided in cash will be held in an interest-bearing escrow account.

Along with the Financial Bid Template and the Project Security Deposit, Bidders should submit additional documentation as follows: documents proving commitment from financial institutions to provide financing; copies of their EPC contract (even if not completely finalized) or other technical documents to prove that they can meet the construction and execution milestones laid out in their proposal; and documentation demonstrating the status of site control.

Financial Bids and other terms of the proposal must be firm for the duration of the procurement process. All bids must be firm up until April 23, 2007, when winning Bidders will be notified. At that point, Bidders whose projects are not selected will be notified and their Project Security Deposit will be refunded. Winning Bidders will be obliged to continue to hold their bids firm and maintain the Project Security Deposit for a period of time not exceeding six months after Contract execution, no later than November 8, 2007. A winning Bidder's Financial Bid (Appendix J) and technical project specifications (Appendix H) will be attached to the Contract, thus ensuring that the parameters on which projects were evaluated and selected will be the project parameters that Connecticut ratepayers receive.

3.8 Award of Contracts

It is expected that winning Bidders will be contacted no later than April 23, 2007. No substantive changes will be allowed to the Contract at this point. The distribution companies and potential Bidders will have had ample opportunity to provide both written and oral comments on the RFP and contract template to the DPUC through to the end of the Pre-Bid Conference.

Once winning Bidder(s) have been notified, they will have fifteen Calendar Days to execute the Contract(s) with winning Bidder(s), and file those executed Contract(s) with the DPUC for approval. The DPUC will be evaluating the approval of the Contract(s) in a contested case proceeding[30] based on the criteria set forth in Section 12(i) of the EIA, notably whether the project(s) (1) result in the lowest reasonable cost of such products and services; (2) increase reliability; and (3) minimize FMCCs to the state over the life of the contract.

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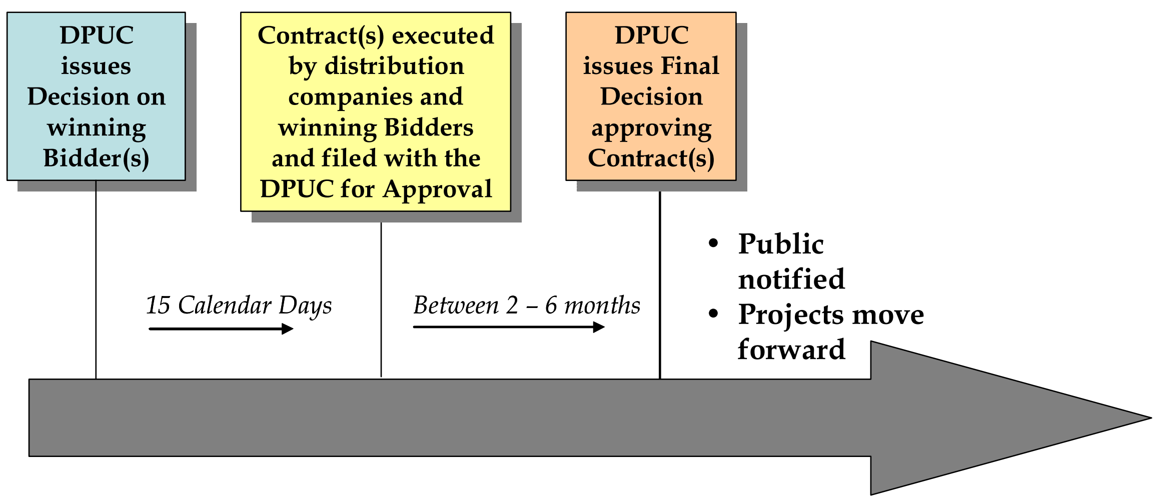
30 There will be a single contested case proceeding for all final Contracts.

This DPUC regulatory approval process could take up to six months to complete. Bids and all other proposal terms must be held firm throughout the entire regulatory approval process, which should be completed no later than November 8, 2007. The DPUC will require that winning Bidders maintain their Project Security Deposit for this entire time period, from December 13, 2006 through November 8, 2007, at the latest. The regulatory approval process will be deemed complete once the Final Decision is issued by the DPUC approving the Contract(s). An overview of this process is shown in the graphic below.

Should the DPUC's regulatory approval process not be completed by 5 pm EPT on November 8, 2007, winning Bidders will be given the option to withdraw their Bids (along with 100% of their Project Security Deposit). All Bidders who choose to continue with the process will have their Financial Bid adjusted to account for changes in underlying costs from December 13, 2006 through November 8, 2007, based on an electricity sector specific Producer Price Index.[31] (The modification of the Financial Bid will apply equally to all projects and will be applied to 100% of the Financial Bid, in order to retain the original balance in the selection process.) If selecting to continue with the process, Bidders must also renew their Project Security Deposit for a maximum of six additional months from November 9, 2007.

Figure 6. Overview of process once winning bidders notified



Once Contracts have been executed, winning Bidders will be required to post their project Completion and Performance Security, and will be refunded their Project Security Deposit (with accrued interest if the deposit was submitted in the form of cash, based on the interest rate established by the financial institution with whom the cash was deposited in escrow). The

[31] The true-up will use the Bureau of Labor Statistics' (BLS) Producer Price Index for electric power generation, transmission, and distribution (Series ID: PCU2211-2211). Note that this index is published with a three month lag. However, the DPUC intends to have the Financial Bids trued-up for the actual change in Producer Prices between December 13, 2006 and November 8, 2007, and therefore, due to the lag in the data series from BLS, there may be a subsequent true up to reflect any changes to provisional data after November 8, 2007.

amounts for the Completion and Performance Security will be calculated using the following parameters (as discussed further in the Contracts):

- $100/kW for all Generation projects until they reach the date of commercial operation, and $25/kW for all Generation projects once they have started Commercial Operation;
- $50/kW for all Demand Response projects until they reach the date of commercial operation, and $20/kW for all Demand Response projects once they have started Commercial Operation; and
- $25/kW for all Conservation and Energy Efficiency projects (collectively, Other Demand Resources) until they reach the date of commercial operation, and $10/kW for all Conservation and Energy Efficiency projects (collectively, Other Demand Resources) once they have started Commercial Operation.

The Completion and Performance Security can be established in the form of cash, a Letter of Credit, or a Performance Bond, as is further described in the Contracts, and may be subject to reduction to the extent that there are offsetting financial assurance requirements mandated by ISO-NE for the same project in order to qualify for participation in ISO-NE Markets.

3.9 General instructions for proposal submission

Bidders should follow the instructions for this RFP as described in this document for submitting their proposals. In the case of any questions, the Bidder should immediately contact the RFP Coordinator for clarification using the email address: RFPCoordinator@Connecticut2006RFP.com.

At any time prior to the different submission deadlines, a Bidder may amend or withdraw a submitted document. Any amendment to a document prior to the submission deadline should clearly indicate what part of the document the amendment is intending to affect or replace. After the deadlines, a Bidder will not be able to amend its proposal except pursuant to a written request by the DPUC requiring additional information or clarification. A Bidder will be able to withdraw its proposal by submitting, in writing, a notice of withdrawal, and submitting it to the RFP Coordinator. A notice of withdrawal submitted by any other method will not be accepted and shall be ignored. A notice of withdrawal without financial consequences to the Bidder may only be submitted before Financial Bids are submitted.

Financial Bids are considered to be binding. A change in terms of the Financial Bid or its withdrawal after December 13, 2006 will result in the forfeit of the Bidders' Proposal Security Deposit. Likewise, a Bidder's inability to execute the Contract, should it be selected as a winning Bidder, will also result in the forfeit of its Project Security Deposit. Proposals shall be irrevocable in the form submitted by the Bidder from the time at which Financial Bids are submitted until November 8, 2007, at the latest.

The same Bidder may submit up to three Proposals for the same site. Mutually exclusive proposals will only be required to submit one deposit, the amount of which will be based on the largest (MW) project. Should the proposals represent different types of resources (large-scale generation versus demand response), the deposit will be based on the project with the largest deposit requirement. Proposals may be limited only in that the Bidder requires the DPUC to select alternative proposals (i.e., Proposal 1 *or* Proposal 2). Proposals cannot be contingent on the DPUC being required to select numerous proposals (i.e., Proposal 1 *and* Proposal 2). If Financial Bids are submitted with the latter contingency, they will be deemed non-conforming and rejected without further review.

The DPUC reserves the right to seek clarification and request additional information, documentation and statements in relation to the proposals. Any such requested information, documentation, or statements should be submitted to the DPUC within five Calendar Days of the date of such a request, though the DPUC may allow a longer period of time to respond if requested.

Bidders are advised that no changes in the Bidder Team or any equity or debt providers identified in the proposal are allowed between the submission of the Financial Bid and the execution of Contracts without the prior written consent of the DPUC.

4 Minimum requirements

This section lists the minimum requirements that all proposals must meet to be eligible to participate in this RFP. Proposals that do not comply with these requirements will be deemed ineligible, and will not be considered for further evaluation.

4.1 General eligibility requirements

The project must represent incremental or new capacity, as defined in Section 2.1, and must be consistent with the description of eligible resources per the EIA, also defined in Section 2.1. The project must be electrically located in the state of Connecticut as defined in Section 2.1 and in the Contracts. Bids will be screened to assess whether or not the proposed project(s) have attributes that would qualify them to participate in the FCM at the contracted summer capacity. In addition, for generation resources, bidders will need to document whether the proposed output is deliverable electrically in the state of Connecticut. The DPUC will work with ISO-NE to confirm such qualifications as part of the Technical Assessment. The Bidder must independently meet all ISO-NE requirements for officially qualifying for the FCM and becoming interconnected to the ISO-NE system. The risk of the project qualifying and being electrically located in Connecticut falls entirely on the Bidder.

The Bidder must be willing to sign the Contract with no substantive modifications, and perform all of its contractual obligations. The Bidder must be willing to participate in relevant ISO-NE Markets, as per the terms of the Contract.

The proposal must be submitted on time and must comply with the submission instructions. Complete and accurate answers must be provided to all questions and templates. Apart from the completion of any blanks or similarly uncompleted information, the Bidder may not make any amendments to the pre-printed wording of the appendices without the prior approval of the DPUC. Any amendments to the pre-printed words on any of the appendices, without prior written approval of the DPUC, will result in the disqualification of that proposal.

The Bidder’s Financial Bid and the terms of the proposal have to be binding through the date specified by the DPUC (November 8, 2007). Bids that are not valid through this date will be rejected. The Project Security Deposit must be provided in the amount required at the time the Financial Bid is submitted. The Bidder must be prepared to provide a Completion and Performance Security if the Bidder is selected and awarded a contract. The Completion and Performance Security is structured to ensure that construction and in-service deadlines are met and that the Supplier’s obligations during the Term of the Contract are satisfied.

4.2 Minimum technical requirements

4.2.1 Bidder team

Bidders must demonstrate project experience, technical expertise, and management capability to successfully develop and operate the proposed project. The Bidder Team must have sufficient prior experience in planning, development, construction, and operation of projects similar to the project(s) described in Bidder’s proposal. Bidders should be able to reference at least one similar project to the proposed project that is already in operation, or should submit other experiences that qualify the Bidder to participate in this procurement process. The Bidder should also inform the DPUC of whether or not it has a third party operator lined up to serve as the project operator and, if so, who this operator is. If not, the Bidder should clearly identify who on the Bidder Team will be responsible for operations.

4.2.2 Project

All projects (except ODR projects to the extent that they are not eligible to participate in ISO-NE Markets) must meet all technical and operating requirements to participate in ISO-NE's FCM, Energy Markets, and the LFRM, if applicable, including any modifications to such Markets, or other product markets that ISO-NE may create as a successor to the FCM, Energy Markets, and LFRM.

Bids must be based on the operating and performance parameters that Bidders are willing to commit to over the term of the Contract for operating performance purposes. For Generation projects, these may include but are not be limited to:

- Heat rate, based on manufacturer's "new and clean" rating and expected operations
- Anticipated heat rate degradation levels over Contract Term;
- Project-specific Target Availability levels;
- Summer and winter demonstrated electric capacity;[32]
- Ramp rate and emergency start capability (if any);
- Dual fuel operating capability (if any);
- Ability to provide electric system ancillary services;
- Remote start, load following and sustained part-load operating capability (if any).

The technology proposed for the project must be capable of producing reliable electric capacity. It is therefore preferable that the required equipment be commercially available and in general use in the US electricity sector. The general specifications of the proposed equipment shall be provided. For projects employing new or untested technology, the Bidder must be specific in describing its plans for providing reliable capacity. This plan of reliability shall include, but not be limited to: a description of the expected and warranted availability of the proposed project; a detailed description of the warranties and liquidated damages available as a result of failure to reach warranted availability; a description of the staffing, operating and other plans the bidder will employ to ensure commercial development and reliable operations; a description of the critical potential failure modes of the proposed technology i.e., "if something is going to fail,

[32] Although the Contract Quantity cannot exceed the summer demonstrated capacity of the project, the Bidder may propose different Contract Quantities for FCM and LFRM settlement in the Contract. The Bid Evaluation will take into account the differences between summer and winter capacity ratings.

what is it likely to be"; and, a detailed listing of spare parts to be housed on site and other actions that will be taken to mitigate the above potential failures.

Bidders should also inform the DPUC as to the status of their equipment order. If the equipment has been ordered, Bidders should include a receipt of the purchase. At a minimum, the DPUC would expect that Bidders have inquired about the availability and pricing of equipment, both of which should be communicated to the DPUC.

Each proposal must identify:

a) The existing interconnection point to the ISO-NE transmission system, if such a connection exists; or

b) If a new interconnection is required, the proposal must include:

   - whether or not the Bidder Team has requested an Interconnection Study to be conducted by ISO-NE;
   - the status of any such request;
   - the status of any required upgrades necessary for interconnection;
   - evidence of qualification to participate in ISO-NE's Markets (if applicable); and,
   - data that the Supplier has (will) provide(d) to ISO-NE regarding its interconnection as highlighted in Appendix H (as applicable).

This RFP seeks firm capacity-backed resource proposals which must be available to help mitigate the impact of FMCCs on Connecticut ratepayers. Therefore, all proposals must have the following attributes:

- The Contract Quantity from the proposed resource must be reliable;[33] and,
- The Contract Quantity from the proposed resource must be quantifiable.

In the case of non-dispatchable projects, the following additional requirements apply:

- The Contract Quantity from the proposed project must be measurable;
- The Contract Quantity from the proposed project must be verifiable; and,
- The Contract Quantity from the proposed project must be sustainable for the term of the Contract.

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33 For purposes of this section, "reliable" shall mean that the amount of and operating characteristics of the Contract Quantity shall be predictable, repeatable and that when called upon, the Contract Quantity shall be available subject only to force majeure, per the terms of the Contract.

4.3 Minimum financial requirements

The Bidder must be able to financially secure the project and the Contract. Financial wherewithal – in terms of adequate cash flow and ability to support the project on the balance sheet - will be assessed in line with the size of the project and proposed project complexity. The DPUC will assess a Bidder's financial stability and viability through the documentation requested in the Financial Questionnaire, attached here as Appendix G, which requests the last two years' financial statements and a credit rating from Standard & Poor's, Moody's, and/or Fitch (if the sponsoring company is rated).

In addition, the Bidder will have to demonstrate that it possesses a viable plan to finance its proposal and should provide as much detail as possible in the Project Financing Template, attached as Appendix J to this document. The Bidder should describe both the requirements of the financing process as well as the status of Bidder's effort to secure financing for the project. Bidders should describe what entity will be providing financing for the project, when they will obtain the financing, and whether or not the Bidder is in possession of commitment letter(s) from lender(s). Firm commitment letter(s) will be a required element of the Financial Bid.

In addition, a Project Security Deposit must be submitted as part of the Financial Bid. Details on the Project Security Deposit are provided in Section 3.7.

4.4 Environmental and siting requirements

The DPUC is seeking projects that have a high degree of certainty of obtaining required environmental and siting permits. The Bidder is responsible for meeting and satisfying all federal, state, and local permits, licenses, approvals and/or variances that are currently required (or may be required in the future) for the development and operation of the project. Bidders must submit a list of all federal, state, and local permits and certifications required in order to develop and construct the project, including site control. Further, the Bidder must describe the current status of its efforts to obtain each of the required permits or certifications. While possessing environmental permits in advance of project selection is not a minimum requirement, the possession of such permits would give Bidders an advantage in the project execution risk assessment.

A further general requirement of the Bidder in the Technical Qualification is to provide evidence of site control. For purposes of the minimum requirements, site control is not limited to outright, unencumbered ownership of the real estate. Options on real estate and other types of contingent commitments are permissible, including non-exclusive commitments.[34] However, the level of site control will directly impact the project execution risk and therefore will be considered in the final Bid Evaluation process.

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[34] So long as such site control commitments are permitted under ISO-NE's qualifications rules for new resources in the FCM. Although the rules will be under development during the RFP process (see http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2006/jul27282006/ a6_fcm_resource_qualification.ppt), the Department will be guided by ISO-NE's proposed draft rules for resource qualification and expects prospective Bidders to be aware of those and comply with any resulting requirements.

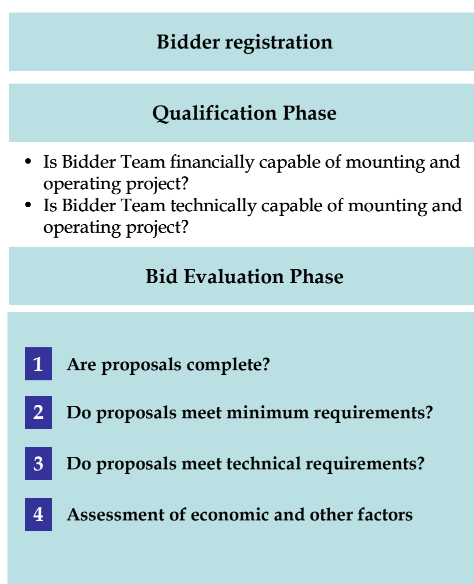
5 RFP evaluation process

5.1 Overview

The DPUC will be adhering to the approved principles and standards developed in Docket No. 05-07-20, *Development of a Process and Standards for Competitive Solicitation of Long-term Projects to Reduce Federally Mandated Congestion Costs*, issued on December 28, 2005, which includes, among other provisions, that "Procurement should be conducted in a manner to cost-effectively promote price consistency and stability and minimize revenue requirements over the long term while also balancing the need to further non-economic policy objectives." (Principle # 2) A full list of the Principles and Standards is provided in Appendix C at the end of this document. In addition, the DPUC also has designed a Code of Conduct for this procurement process, which is attached as Appendix L. The Code of Conduct establishes the process for information dissemination. Only the DPUC and its consultants will have access to the bid submissions prior to project selection and award, as discussed in the Code of Conduct.

The RFP evaluation process will have several phases through which each proposal must pass. There are three general phases to the RFP process: Bidder registration (all Bidders must be registered in order to have their proposals assessed); the Qualification Phase, where the Bidder Team's financial and technical abilities are assessed; and the Bid Evaluation Phase, where the technical and financial proposals are assessed.[35] If a proposal fails to pass the minimum requirements of one phase, it will not pass on to the next phase and will be disqualified.

Figure 7. Overview of RFP evaluation framework



35 Bidders must submit technical proposals during the Qualifications stage, describing the project's technical parameters. However, these technical proposals may be amended up to the Financial Bid stage, as discussed in Section 3.6 and in Section 5.2 below.

The following subsections address each of the four steps in the Bid Evaluation Process. For additional information on the Bidder Registration Process, please see Section 3.4. For additional information on the Qualifications Process, please see Section 3.6.

The DPUC designed the Bid Evaluation process to focus primarily on the three priorities laid out in the EIA for approving Contracts resulting from this procurement process. These priorities are delineated in Section 12(i) of the EIA and include: (1) resulting in the lowest reasonable cost of such products and services; (2) increasing reliability; and (3) minimizing FMCCs to the state over the life of the Contract. These priorities are explicitly analyzed in the Economic Analysis. All other factors and preferential criteria mentioned in the EIA are considered secondary for the purposes of Bid Evaluation, and therefore are not given as much weight as the Economic Analysis. The Economic Analysis will be weighted 85% in the Final Project Score while the Other Factors will represent the remaining 15%. In response to stakeholder requests, an Excel-based model which illustrates the Bid Evaluation calculation process using fictitious sample data has been attached to the RFP and will also be posted on the RFP website. The Bid Evaluation Demonstration model highlights the calculations for measuring benefits and costs for a stylized project under the Economic Analysis and illustrates how the Other Factors will be incorporated into the Final Project Score.

5.2 Are proposals complete?

The first phase is an administrative one to ensure that the Bidder has complied, in a timely manner, with all submissions in the Financial Bid Phase, and to make sure that all forms are correctly and completely filled out. The DPUC provides a checklist below so that Bidders can monitor their submissions and make sure that they have complied with all filing requirements. All forms must be submitted by December 13, 2006 at 5 PM EPT.

Bidder checklist:

The following documents should have been submitted during the Qualifications Process. If necessary, revisions to these documents can be submitted up until the date that Financial Bids are due. However, Bidders must provide notice of such changes prior to the Financial Bid submission deadline and explain the basis for the revisions to the satisfaction of the DPUC.

- √ Minimum Technical Requirements (see Appendix F)
- √ Project Description Questionnaire (see Appendix H)
- √ Anticipated Project Financing Questionnaire (see Appendix I)

The following documents must be submitted along with the Financial Bid.

- √ Financial Bid Template (see Appendix J)
- √ Proposal Security Deposit
- √ Documentation from financial institutions demonstrating financing commitments

- √ Documentation of the negotiations with EPC contractor and/or equipment suppliers to demonstrate feasibility of construction milestones and equipment purchases
- √ Documentation demonstrating site control
- √ Documentation showing receipt of or status in filing for necessary federal, state, and local approvals and/or permits, including all necessary environmental permits

These documents, in the aggregate, will represent the Proposal for a project by a Bidder. Certain documents from the Proposal (such as, but not limited to, Appendix H and J) will be incorporated directly into the Contract, if the Project is awarded a Contract.

5.3 Do bids meet minimum requirements?

The second phase of the Bid Evaluation Process examines each proposal to ensure that it meets the general eligibility requirements laid out in Section 4.1. To recap, these requirements include:

- Projects must offer incremental capacity that is electrically located in Connecticut, and therefore qualify for Connecticut's LSR in the FCM.
- Generation projects must also satisfactorily show that electrical output (energy) from the facility can be deliverable within the state of Connecticut under a specified range of conditions as described in ISO-NE's publicly available load flow cases (see footnote 3);
- Projects must demonstrate some level of site control (which would be acceptable to ISO-NE for qualification for FCM).
- Projects must be considered eligible under the criteria of the EIA. The Bidder is expected to describe and demonstrate the proposed project's eligibility in the Qualifications material.
- All Generation and Demand Response projects (and ODR Projects, if and when they become qualified to participate in the FCM by ISO-NE) must be technically capable of participating in ISO-NE's Forward Capacity Market as well as other ISO-NE Markets specified in by the Bidder for each proposed project in the Qualifications and reaffirmed in the Financial Bid. The Contract will reflect this representation by the Bidder.
- Bidders must be willing to abide by the restrictions on bidding in ISO-NE markets set forth in the Contract, and must be willing to perform as obligated in the Contract (if relevant).
- Bidders must propose a viable financing plan for the project and demonstrate firm commitment from financial institutions or other entities.
- Bidders must identify the applicable Contract (from the three templates provided) and must be willing to sign that Contract without substantive modifications.

- Financial Bids must be binding through April 23, 2007, with the understanding that winning bid terms must be binding for an additional six months from the date of contract execution, no later than November 8, 2007.

- A Project Security Deposit of the appropriate amount must be submitted with the Financial Bid, and will be released, upon the date of selection of winning Bidders, to those Bidders that are not selected.

5.4 Technical Assessment of bids

The third phase of the Bid Evaluation Process will assess the technical specifications of the project to ensure that the project is technically feasible, that it is deliverable electrically within the state of Connecticut at the level of proposed contracted capacity, and that the project is capable of participating in the ISO-NE Markets it has committed to participate in.

The DPUC and its consultants will focus on assessing the project's capabilities (in terms of capacity and ability to participate in ISO-NE markets), critically assessing whether or not projects are capable of performing at the levels specified in the project description forms, and whether or not these parameters are in line with the requirements of ISO-NE Markets.

The technical evaluation will include the issue of assessing project qualification for the FCM and whether the output from the project is deliverable within the state of Connecticut. The Bidder is required to document in its bid submission how it meets the requirements of the RFP, including how it qualifies for Connecticut's LSR and the RFP's requirements regarding energy deliverability, if applicable. The DPUC will rely on the information provided by the Bidder on its proposed project in conjunction with the information ISO-NE has on the ISO-NE system to determine whether or not the project can be considered to be electrically interconnected within the state of Connecticut and whether the energy produced by the project (for Generation projects only) is deliverable based on existing system conditions and a reasonable range of future system conditions, for example, taking into account the projects already in the Interconnection Study queue. Projects must pass the technical assessment of project capability to pass onto the next phase of bid evaluation.

The Bidder is responsible for seeking appropriate review by ISO-NE, as required. It is the responsibility of the Bidder to apply for and satisfactorily complete the ISO-NE's requisite assessment for interconnection, as well as the above specified requirements that ISO-NE may impose prior to permitting participation in the ISO-NE Markets (such as the qualification of new resources for the FCM). Suppliers may face reduction in payments, liquidated damages, and possibly Early Termination, if they do not achieve satisfactory compliance with the deliverability and qualification requirements in the Contract. Bidders will be responsible for all costs associated with any analysis required by ISO-NE for interconnection and qualification for participation in ISO-NE Markets.

5.5 Bid Evaluation process once the Technical Assessment is complete

Once projects have passed the first three phases (any project that does not pass one of the first three phases will be disqualified), projects will be analyzed in terms of their net benefits in the Economic Analysis, and their contribution to the Other Factors highlighted by the EIA.

The Bid Evaluation will assess projects based on the three priority objectives of the EIA (as listed in Section 12(i)):

- **Lowest reasonable cost:** By evaluating projects using a cost-benefit framework, the DPUC is ensuring that projects with the lowest possible projected net costs (and highest possible projected net benefit, taking into account the analysis Other Factor) are identified and selected.

- **Increase reliability:** The DPUC includes, in its baseline analysis, scenarios that represent low levels of installed capacity and high levels of demand in order to simulate the ramifications of supply interruptions (or supply insufficiencies in those ISO-NE Markets where supply interruptions are irrelevant) and the value of such interruptions from the perspective of ratepayers (based on an approximation of Value of Lost Load by the offer cap in the relevant ISO-NE Markets). This modeling approach reflects the ability of proposed projects to assist in avoiding supply interruptions or supply insufficiencies, and therefore allows the DPUC to project the benefits associated with improvements in system reliability.

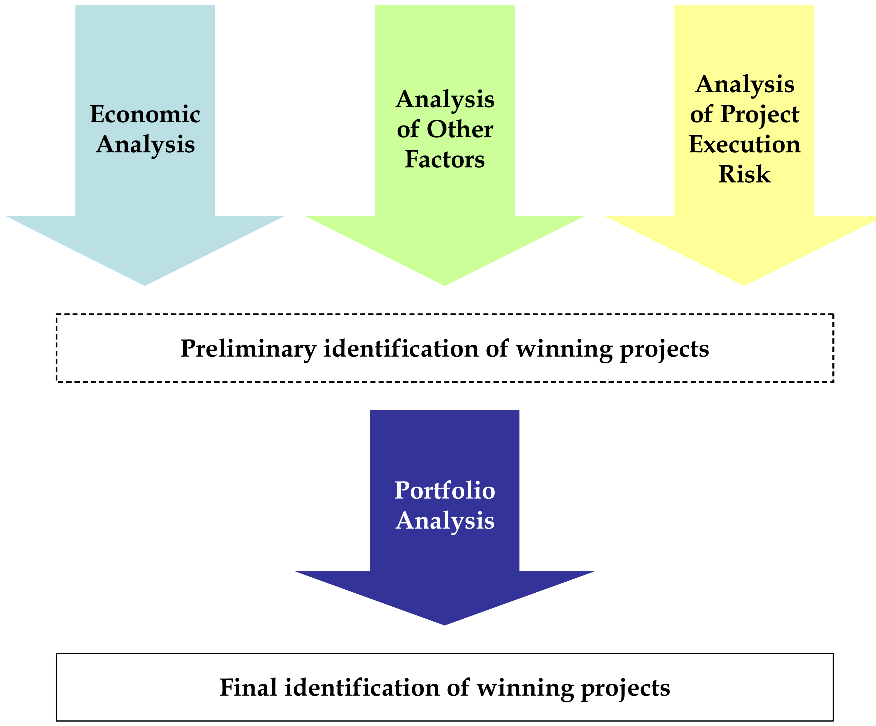
- **Minimize FMCCs:** All three major FMCC components – energy, capacity, and forward reserves – constitute the basis of the economic analysis, as described earlier in this section. The results of the analysis will clearly identify the projects that have the greatest expected ability to decrease FMCCs, based on an analysis of changes in the projected costs to load. Therefore, proposals will be evaluated on their ability to affect capacity, Locational Forward Reserve, and energy prices in the ISO-NE system based on what ISO-NE Markets the Bidder committed to in his Financial Bid. The commitment to participate in such markets will be binding in the Contracts.

The Economic Analysis will be worth 85% of the project's assessed value and the project's performance on other criteria (i.e., Other Factors) will be worth 15% of the Final Project Score.

Project execution risk will be assessed in comparative terms, ranking the projects among one another, as discussed further in Section 5.5.3.

Finally, once the DPUC makes a preliminary identification of winning projects, it will assess the aggregated portfolio of individual projects to ensure that the portfolio results in a net positive value for Connecticut ratepayers and that there is no detrimental market power concerns for the ISO-NE Markets resulting from these Contracts.

Figure 8. Overview of Bid Evaluation process after the technical assessment



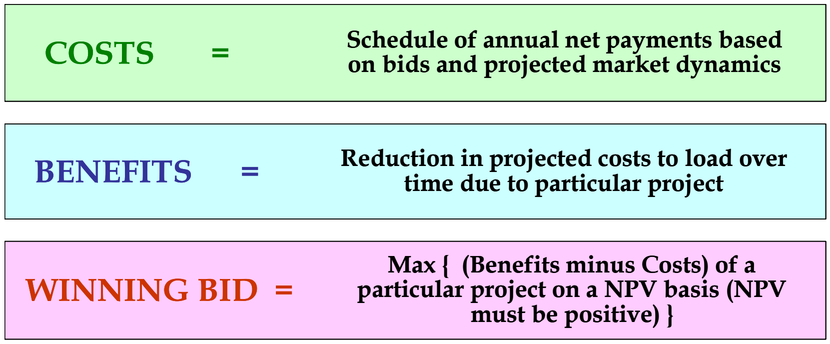
Each of these analyses is discussed in the subsections below.

5.5.1 Economic Analysis

For the Economic Analysis, the DPUC will use a cost-benefit framework to analyze the difference between the expected benefits and costs of proposed projects on a Net Present Value basis. The DPUC has prepared a "baseline" outlook of market prices in the relevant ISO-NE product markets (Energy, FCM, and LFRM), and resulting costs to load to Connecticut ratepayers. This "baseline" outlook establishes a projection of the costs to Connecticut load due to market activity under various different scenarios. Each project's impact on this baseline outlook will be simulated, taking into account that projects may affect and change market evolution once they are introduced. The DPUC will use these market simulations to estimate each project's potential to reduce total costs to Connecticut ratepayers as measured against the "baseline" outlook. It is important to note that the "baseline" outlook is not a single scenario, but rather a composite of various, plausible future market conditions.

The DPUC wishes to reduce the total costs to load as soon as possible. Therefore, projects providing more immediate benefits will be more highly valued than those that only provide benefits in the distant future. While Contracts may have terms up to 15 years, the DPUC will allow Bidders to select the term (which must be less than 15 years) that they believe balances the needs of the projects and the cost and benefits to ratepayers. Therefore, the DPUC will analyze bids on a Net Present Value (NPV) basis to align projects for an "apples to apples" comparison (please note that one of the Other Factors will also consider the ramifications of front-loading of costs by reference to annual cost-benefits and whether there are years where the annual amounts are negative) . The DPUC will use a single discount rate that is consistent with the allowed rate of return of the electric distribution companies in Connecticut (9.8%).[36] All bids will be discounted back to current (2006) dollar terms regardless of their on-line date.

Figure 9. Conceptual overview to cost-benefit framework



Project costs will be measured by calculating the NPV of net payments to the Supplier over the Contract Term based on the Contract Quantity, and the difference between the Annual Contract Price submitted by the Bidder in the Financial Bid Template and projected market clearing prices based on the market simulations taking into account the proposed project (and only for those projects where market clearing prices will be used to settle the Contract), as well as payments of the supplemental capacity payment under the Call Option, if elected by the Bidder.[37] Project costs will also take into account the fact that under certain market conditions, a project may be increasing total costs to ratepayers because more capacity is being procured than would otherwise occur in the market (for example, if the market (such as LFRM or FCM) is going to have periods of insufficiency, then the Contract will represent additional capacity that would otherwise not have been procured in that market). In such an instance, the project costs will incorporate the entire Annual Contract Price. Note that costs arising from additional ratepayer funding (such as from the Connecticut Clean Energy Fund or the Connecticut Conservation & Load Management Fund) will also be included as a cost in the cost-benefit analysis.

Project benefits will be calculated in a two-step process. First, the DPUC will calculate the costs to Connecticut load without the impact of this RFP (i.e., without any of the proposed projects, but with the proxy capacity developed for each case in the "baseline" outlook). Then, based on the technical parameters submitted by each Bidder for each project, the DPUC will calculate the costs to Connecticut load assuming that the proposed project comes on-line (these project-specific cases will also dynamically adjust the proxy capacity, as some of the actual proposed projects are likely to displace future proxy capacity in the "baseline" outlook).

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36 See footnote 14 for an explanation of this figure.

37 For ODR projects which are not settling against the FCM, the project cost will be based on the Annual Contract Price and the Contract Quantity.

Then, the DPUC will calculate the NPV of the reduction in total costs to load, composed of:

- Energy Market costs (Locational Marginal Price forecast by the modeling multiplied by the amount of energy consumed in Connecticut);

- FCM payments (the Auction Clearing Price in the applicable FCA multiplied by the requirement relevant for Connecticut, which will be defined by Connecticut's share of the ICR or the state specific LSR, if Connecticut is a separate Capacity Zone); and,

- LFRM payments (based on the Auction Clearing Prices in the LRFM Auctions and the projected Locational Forward Reserve Requirements, with adjustments for the specific settlement technique identified in the Market Rules for LFRM, for example, the netting of Auction Clearing Prices from the FCM from the LFRM Auction Clearing Prices and the formulaic approach for calculating costs to load based on the weighted sum of procurement costs for each Reserve Zone and the 'Rest of System' area); and

- The benefit to ratepayers of the effective price cap on energy for projects selecting the Call Option will also be incorporated into the benefit stream.

In other words, the costs to Connecticut load *with* the proposed project are compared to the costs to Connecticut load *without* the project (in other words, the "baseline" outlook), resulting in an NPV of the project's anticipated benefits.

Note that for conservation, energy efficiency, and demand response projects, project benefits will be analyzed through assumed reduced electricity demand and consumption (as appropriate per terms of the technical description submitted in the technical proposal). Reduced energy consumption will likely decrease energy prices in the region, thereby reducing total costs to Connecticut load. Likewise, demand side projects would decrease the ICR in the FCM, thereby reducing the amount of supply required, resulting FCM prices, and costs to load. ODR projects that are not eligible to participate in the FCM will have Contracts that do not settle against this market; this will not penalize them in the bid evaluation process, which assesses net benefits and costs to end-users, and those projects will still have an impact on the FCM and the Energy Markets, because they reduce peak demand and energy usage.[38]

Finally, the NPV of the project's costs are subtracted from the project's benefits, resulting in the proposed project's net benefit on an NPV basis. Given the DPUC's mandate to protect Connecticut consumers in general, and the specific mandate of the EIA to reduce the impact of FMCCs on Connecticut ratepayers, the DPUC will not accept any bids that do not result in a net

38 As described in the ODR Contract and in the Financial Bid template, ODR projects (i.e., conservation, energy efficiency, and other demand resources) will have their capacity (ODR Demand Reduction Value) grossed up to account for avoided peak demand transmission and distribution losses and the ICAP Reserve Margin (if applicable) in accordance with prevailing ISO-NE practice). Therefore, the effective Contract Quantity will be higher than the gross capacity of the project. This higher Contract Quantity which will be incorporated into both the Bid Evaluation and into those projects' monthly payment streams under the ODR Contract.

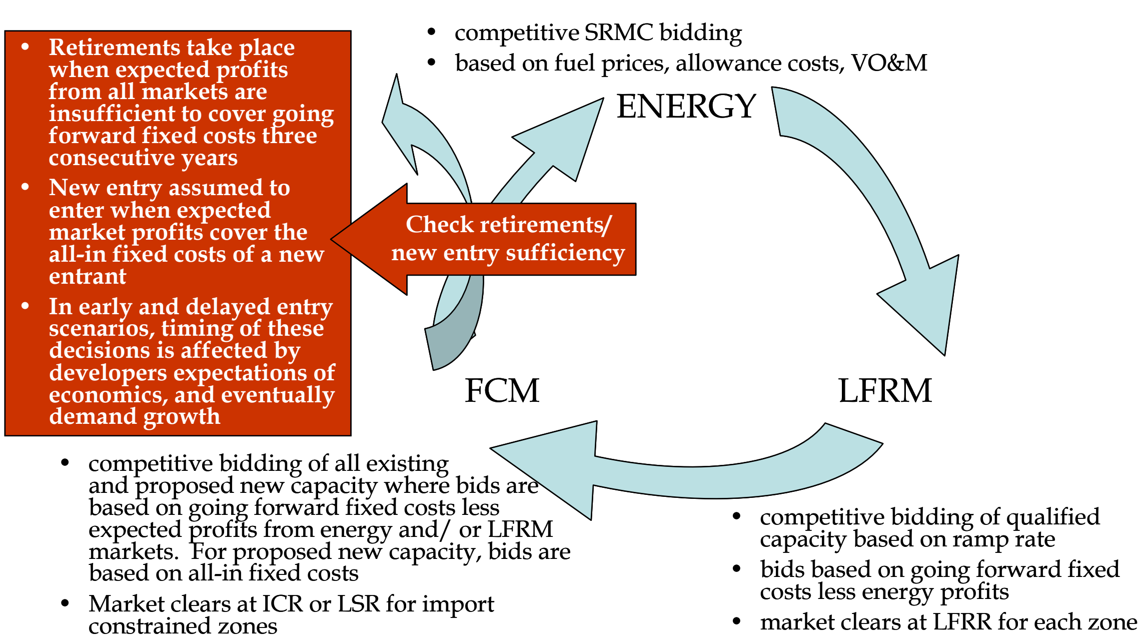
positive value to Connecticut ratepayers. That is, the DPUC will only accept projects whose net benefits exceed their net costs. The decision about which bids do not offer positive net benefits to Connecticut ratepayers will only be made after an extensive economic analysis of each project and its impact on the New England markets for energy, capacity (FCM), and non-spinning reserves (LFRM).

This part of the Bid Evaluation will be worth 85% of the Final Project Score.

5.5.1.1 Modeling overview

Future market prices in the ISO-NE Markets will be projected using London Economics' proprietary production cost-based network simulation model, POOLMod, along with a suite of Excel-based models created specifically to project market clearing prices (and costs to load) in the FCM and the LFRM. The three ISO-NE Markets - Energy, FCM, and LFRM – are interlinked and the models respect those linkages. For example, generators are expected to offer their capacity (under rational bidding behavior) into the FCM at a price equal to their going forward fixed costs less expected profits from the Energy Market. Offers into LFRM are also based on going forward fixed costs. The prices received in the LFRM are also expected to be netted against the capacity clearing prices received in the FCM. The diagram below, Figure 10, highlights the process and sequencing used in the modeling and the inter-relationships between the three models, and the entry and retirement decisions of resources. Further below, there is a description of each of the models and key algorithms.

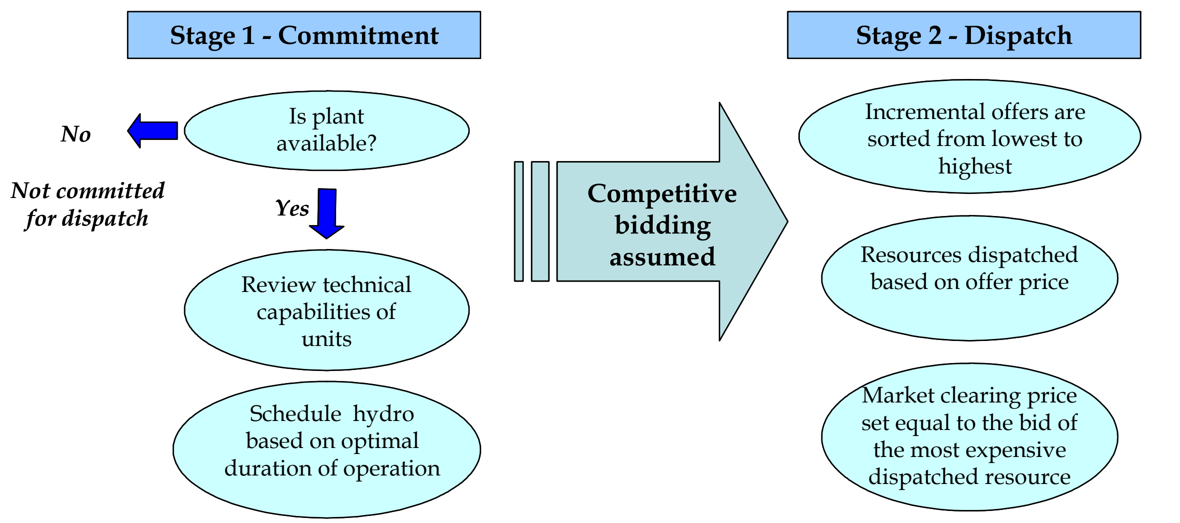
Figure 10. Flow diagram of energy, LFRM and FCM modeling



POOLMod: The DPUC will utilize London Economic's proprietary network simulation model as the foundation for the energy price forecast. POOLMod will simulate the dispatch of New England's generating resources (and imports) on a least cost basis in order to meet projected hourly load (and export demand), subject to technical constraints on operations for generation and availability of transmission capacity.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing[39], commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a 'near' optimal maintenance schedule on an annual basis having regard for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 11. POOLMod's two-stage process



POOLMod next commits and dispatches resources on a daily basis. Commitment is based on the schedule of available resources net of maintenance, and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation in the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate to that same schedule (i.e., the resource they are displacing).

POOLMod is a transportation-based model, so it takes into account thermal limits on the transmission network. For the Economic Analysis, the entire ISO New England's control area will be modeled on a zonal basis, consistent with the assumptions used in RSP 2006.[40]

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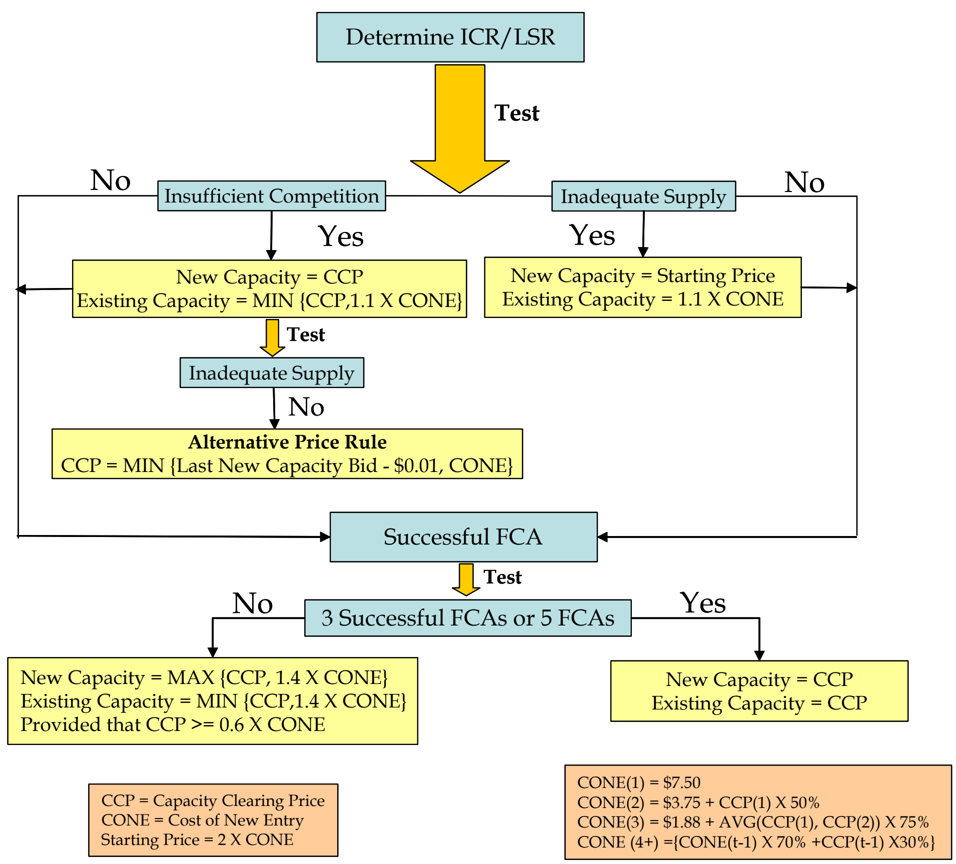
39 The shadow price of a hydroelectric unit is equal to the opportunity cost of its water. POOLMod shadow prices hydro units at the value of the incremental unit of energy needed in the market at a particular time, consistent with rational bidding behavior observed in actual markets.

40 Imports and export demand from adjoining markets will also be considered in POOLMod simulations in order to realistically capture the actual operating dynamics in the ISO-NE Energy Market, and to maintain linkages to the FCM model, which incorporates the fact that resources from external markets may also bid

FCM: The FCM model simulates the capacity clearing price of each Forward Capacity Auction (FCA) using a single-shot auction platform[41] and the rules specified in the Settlement Agreement. The model is set up to simulate separate auctions for each defined import-constrained zone, as necessary. After demarcating the various zones and location of capacity (based on the rules specified in the Settlement Agreement), the model takes the projected bids of qualified capacity (existing and new) and sorts the capacity based on bid price, thereby forming a supply stack. The capacity clearing price is determined at the intersection of the supply stack and the procurement target, the Installed Capacity Requirement (ICR) or Local Sourcing Requirement (LSR). The model has been expanded to take into account the various pricing rules in the Settlement Agreement, including the Cost of New Entry (CONE) calculation, the capacity clearing price floor and ceiling for the initial FCAs, and the alternative pricing rules, as illustrated in the figure below.

Figure 12. Flow diagram of capacity modeling pricing structure



into the FCM, and that the ICR for New England takes into account the tie benefits that ISO-NE relies on to maintain resource adequacy.

41 A single-shot auction method is used because the modeling is assuming competitive bids from resources, i.e., resources will offer the best, lowest bids based on their individual cost structures. Based on rational bidding behavior, resources would not and could not profitably deviate from this competitive bidding strategy. The price signaling effects and competitive dynamics that are motivated through the repetitive process embodied in a descending clock auction format would not produce different results from a single shot auction under such modeling assumptions.

Rational behavior and competitive bidding has been assumed throughout the Economic Analysis.[42] Therefore, capacity resources are assumed to bid into the FCA based on the minimum going forward costs. For Existing Capacity, those minimum going forward costs are defined as fixed operations and maintenance costs (FO&M) and interest expense and debt principal repayment (collectively, the debt charge). For New Capacity, the minimum going forward fixed costs will include all fixed costs, including return on equity as well as the debt charge and FO&M. New Capacity will not have committed to development fully until they are awarded a contract in the FCM (i.e., they do not have any sunk costs, in contrast to existing generators), and therefore their avoidable costs are much higher. Once New Capacity clears a FCA, it will be treated as Existing Capacity for subsequent FCAs. The ICR and LSR forecasts will be based on the methodology documented in the Needs Assessment.

LFRM: The LFRM model simulates the auction clearing process of each summer season Locational Forward Reserve Auction (LFRA) over the forecast time horizon. Qualified resources are identified and sorted based on their modeled bid price. The LFRM identifies qualified resources based on their technical capability (ramp rate), economic qualification (proxied by an analysis of the strike price (Forward Reserve Heat Rate) and each resource's modeled technical heat rate[43]), and location. The bid price for LFRM-qualified resources is based on minimum going forward fixed costs, i.e., FO&M and debt charge. Consistent with current rules with respect to settlement during the Transition Period and anticipated rules for settlement once the FCM starts, the bids that resources offer into the LFRM are net of revenues earned in the FCM. The Auction Clearing Price is based on the intersection of the LFRM bid stack for each LFR zone and that zone's Locational Forward Reserve Requirement (LFRR). The LFRR projections are described further in the Needs Assessment.[44]

5.5.1.2 Scenario analysis

The "baseline" outlook represents a composite of market outcomes under various conditions such as different supply-demand balances, different fuel price outlooks, varying levels of environmental regulation, and various transmission investment scenarios. These parameters (supply, demand, fuel prices, environmental regulation, and transmission) are considered to be primary drivers of outcomes in the competitive power market in New England. Therefore, the "baseline" consists of a number of scenarios – rather than a single case. A scenario-based

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42 It is standard practice for economic models to make such assumptions. The DPUC will, however, test for increased market power potential for successful Bidders in the Energy Market in the final stage of the Economic Analysis, namely the portfolio bid analysis.

43 The Forward Reserve Heat Rate (strike price) changes dynamically in the LFRM modeling based on the results of the Energy Market modeling, consistent with the current ISO-NE rules. A resource can qualify to bid into the LFRM if its heat rate is greater than the Forward Reserve Heat Rate implied by the strike price or if the resource is expected to be operating at partloaded levels (again, based on the heat rate of the resource vis-à-vis forecasted market prices), and therefore not have a substantial opportunity cost for the capacity being offered into LFRM.

44 On August 31, the first LFRA was conducted. The results indicate that LEI's projections of LFRM supply are in line with supply offered into the auction. In the auction, 659 MWs were offered (all of which cleared), while in our model the MWs offered and purchased are 711 MW in CT. This difference of 52 MW is negligible given the fact that this was the first locational forward reserve auction ever held.

approach allows us to have a representation of the embedded uncertainty in market outcomes resulting from these primary drivers.

The revised August 25, 2006 Needs Assessment documents the various supply and demand combinations that will be investigated. These four cases are constructed using three different ISO-NE demand forecasts, along with varying views on the evolution of new supply in New England (including the impact of more stringent environmental regulation), as summarized in Section 2.2 of this RFP. All the scenarios start with existing supply, including capacity resources identified in the 2006 CELT report, Project 100 capacity, SWCT Gap RFP, ISO-NE demand response program resources, recently approved conservation measures (approved by the DPUC). Generic capacity is added to the scenarios based on the case-specific assumptions on the pace of entry and responsiveness to investors to market conditions.

In addition to the four supply-demand scenarios described in the revised August 25, 2006 Needs Assessment, future market prices will also be simulated under three different fuel price projections (which is described further below). The "baseline" outlook will also include sensitivities that assess the impact of delayed transmission investment (i.e., the commercial operation date of known expansion projects is delayed), and the impact of natural gas supply shortages.[45]

The marginal probability associated with each scenario in the "baseline" outlook has not been quantified. The DPUC believes it is necessary to assign a fixed probability weighting to each scenario in order for the DPUC to objectively estimate the benefits of projects and rank the proposed bids.

5.5.1.3 Summary of major assumptions

The key inputs into the modeling include: demand forecasts, existing generating capabilities (economic and technical operating characteristics), and characteristics of existing demand-side resources, interzonal transfer capabilities, import and export trends, transmission thermal capabilities, fuel prices, and technical and financial characteristics of new generation technologies. The table below highlights the major inputs into each of the three market models.

The assumptions for the "baseline" outlook were developed using the most current data available from ISO-NE, the US Department of Energy (DOE)'s Energy Information Administration (EIA), FERC, and other public sources, including NYMEX. If and when more current data becomes available, the assumptions used in the "baseline" outlook will be updated and revisions posted for all prospective Bidders and stakeholders on the RFP website.

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45 Stakeholders have suggested other possible scenarios including reducing peak demand by 13% or incorporating possible future environmental regulations. However, the DPUC can only incorporate existing or approved projects (for example, policies with funding sources). If the state takes concrete actions regarding some of these policy issues before Bid submissions are due, we will update the assumptions and inform bidders accordingly.

Input Parameter	Energy Market	FCM	LFRM
Energy and Peak Demand forecast (by RSP sub-region)	Hourly demand data used in commitment and dispatch phases of the Energy Market simulations	Annual peak demand used to develop ICR	Demand implicitly used to extrapolate ISO-NE's LFRR forecast (flows on key transmission paths from Energy Market modeling used to determine change in ERS after 2010)
Existing Generation Resource - Capacity	Summer and winter demonstrated capacity ratings from ISO-NE's *CELT 2006* used to determine supply curve for Energy Market	Summer demonstrated capacity rating from ISO-NE's *CELT 2006* used to determine supply curve for FCA	Summer demonstrated capacity rating from ISO-NE's *CELT 2006* used to determine supply curve for LFRA
Existing Generation Resource – Operating Parameters	POOLMod requires the following types of inputs: resource-specific heat rates, minimum stable generation levels, ramp times, forced outage rates, and maintenance weeks (as well as daily energy schedules, storage capacity, and seasonal sculpting of maximum capability for energy constrained resources like hydro)	Availability parameters in the Energy Market implicit in the settlement for the FCM	Ramp rates are used to determine participating supply from resources, and heat rates are used to identify qualified resources for the supply curve for LFRA
Existing Demand Response (DR) Resources – Capacity	DR information based on ISO-NE's RSP 2006 and data on new projects awarded contracts in DPUC programs, used to determine supply curve for Energy Market	DR information based on ISO-NE's RSP 2006 and data on new projects awarded contracts in DPUC programs, used to determine supply curve for FCA Our analysis assumes that 50% of all non-emergency generation DR resources will continue throughout the forecast period. Emergency generation (qualified as GAP RFP) is assumed to retire prior to the summer 2008 period.	Not Applicable

Input Parameter	Energy Market	FCM	LFRM
New Generation Resource – Operating and Financial Parameters	Operating Parameters, which affect the supply curve in the Energy Market, are based on industry standards for a variety of current new entrant technology, and expected gains over time in thermal efficiency. Financial Parameters are also based on industry standards, adjusted for New England conditions. Financial Parameters dictate when New Generation Resources are introduced.	Financial Parameters of New Generation Resources impact the bids in the FCM	Financial Parameters of New Generation Resources impact the bid price of such resources in the LFRM
Fuel Prices	Fuel prices used to determine bids of resources and shape of supply curve for Energy Market; projections developed from current market futures and forwards and EIA's long term regional forecast	Fuel prices are implicitly used in FCM, as bids into FCM are a function of the energy profits earned by resources from the Energy Market and LFRM	Fuel prices are implicitly used in LFRM: (1) strike price is based on modeled outcomes in the Energy Market from prior periods and (2) resources' bids into LFRM are a function of the profits earned by resources from FCM
Transmission Thermal Capacity along Internal Interfaces	Thermal Capacity Limits are based on current TTCs as provided by ISO-NE. The TTCs impact dispatch in the Energy Market modeling and allows for the simulation of congestion and marginal losses	Thermal Capacity Limits define import capability and are used to determine whether a zone is Import-Constrained. TTCs of Internal Interfaces are also used in the estimate of LSRs	Thermal Capacity limits are implicitly used as the power flows across the SWCT, CT and NEMA/Boston interfaces are used in the calculation of LFRR.
Import Supply and Export Demand	Import and export dynamics affect the commitment and dispatch phases of the Energy Market. Import and export assumptions derived from observed actual flows into and out of New England, adjusted for expected dynamics in neighboring markets over the forecast time horizon	Secure import quantities over External Interconnections (e.g., tie benefit) used in determination of the ICR. Firm Imports, as described in ISO-NE's CELT 2006, are deemed to participate in the FCM as import bids.	Not Applicable

Bidding assumptions: A competitive market dynamic was assumed, where prices are based on the most economic offers and generators are assumed to behave rationally. Therefore, in the

Energy Market, generators make offers based on their short run marginal costs (SRMC), which are related to fuel costs and other variable operating costs. The fuel component of SRMC is derived from fuel prices and heat rates (thermal efficiency); variable operating costs include variable operations and maintenance costs (VO&M) and emissions reduction costs (i.e., costs of purchasing allowances and emission reduction credits to meet environmental compliance requirements). In the FCM and LFRM, resources are assumed to offer at their minimum going forward costs (net of profits in other markets). Fixed costs were developed using generic fixed costs by technology/fuel type (taken from actual sample data filed by generators with FERC), and generic capitalization structures and financing terms (varied, where appropriate, by technology).

Existing capacity: Capacity ratings for existing resources were taken from ISO-NE's CELT report, as highlighted in the figure below. For operating parameters, a standard set of assumptions (on minimum stable generation, ramp rates, forced outages, scheduled maintenance, etc.) was incorporated into the model to represent plant dynamic constraints. The assumptions for these types of parameters are driven by "normalized" or average industry benchmarks. For example, peaking units in the system are assumed to be the most flexible units on the system, based on ramping capability and minimum stable generation (the lowest level of capacity at which the unit could generate energy).

Figure 13. Existing resources based on summer rating by RSP sub-area and by fuel in 2007

	CT	SWCT	Norwalk	Rest of New England	Total
Nuclear	2,037	0	0	2,411	**4,448**
Coal	181	372	0	2,218	**2,771**
Gas	0	662	0	7,037	**7,699**
Oil and dual-fuel	2,014	768	396	7,652	**10,830**
Other	124	65	0	789	**978**
Hydro	34	116	0	3,206	**3,355**
Demand Response*	320	255	0	219	**794**
Total	**4,710**	**2,237**	**396**	**23,532**	**30,876**

Source: ISO-NE CELT 2006

* Note that the capacity demand response/ interruptible demand programs presented above already incorporate the weighted average performance rates for each of these resources, based on ISO data. See ISO-NE presentation, "*Demand Response*", June 6, 2006. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2006/jun62006 /demand_response.pdf

Maintenance data and forced outage rates data is based on historical trends observed across the US by NERC and compiled in their *GADS database*, as well as ISO-NE's estimate of historical, technology class-average forced outage rates for the system. Although the *GADS database* is not unit-specific, the inputted parameters are differentiated by technology and/or fuel and/or capacity size. Heat rates are resource specific and are based, where available, on actual average heat rates. Where data is unavailable, industry-standard rates are used. VO&M were derived from cost data filed with FERC by ISO-NE generating facilities. VO&M is assumed to not change over time in nominal terms, which implies some efficiency gains over time.

Variable operating costs also incorporate adders for allowance costs for emissions compliance for SO_2, NOx, and CO_2. Each thermal plant's reported historical emission rates were first examined. For SO_2 and NOx, when a plant's emission rates exceed the state-specific environmental emission compliance limits,[46] a plant owner can either choose to install pollution abatement equipment or purchase emission allowances. A decision is made depending on which approach costs less on a present value basis. When a plant owner chooses to install pollution abatement equipment, capital costs (amortized over 5 years) are added to its going forward fixed costs. On the other hand, if a plant owner chooses to purchase emission allowances, allowance costs are added to the variable costs. CO_2 emissions compliance only applies to current RGGI states (i.e. Connecticut, Maine, New Hampshire, and Vermont), and is modeled using an assumed CO_2 emission cost adder derived from ISO's modeling for RSP 2006:[47] gas-fired combined cycle units incur an additional adder of $2.1/MWh, oil-fired peaking units incur a charge of $5.4/MWh, and coal baseload plants incur an additional charge of $4.4/MWh.

A plant will be retired when profits are insufficient to cover its going forward fixed costs under rational investor behavior.[48] In order to model this paradigm, each plant's profitability is analyzed during the modeling timeframe. For each plant, modeled energy revenues, LFRM payments and FCM payments are catalogued and these profits are compared to each plant's estimated going forward fixed costs to derive a plant's net profit. If a plant has negative net profits for three consecutive years, it is retired. A three-year rule was used to reflect the observed inertia in deregulated markets across the US towards permanent plant closures, even in adverse market conditions.

New (generic) capacity: Any long term modeling must incorporate introduction of new capacity in order to be a reasonable and plausible outlook for the future. A pragmatic approach is taken in the modeling, looking at "just in time" entry of generic (proxy) capacity, as well as possible delays or accelerations in new build (boom and bust cycles) based on developers' perceptions about future demand and overall market uncertainty.

New entrant operating and financial parameters are necessary inputs across all three models, energy, LFRM, and FCM. The assumptions on new entrant costs and technical capabilities were derived from London Economics' New Entry Trigger Price Model (NETPm), which provides a component-by-component analysis of the break-even price level of different technologies, and thereby documents the operating and finance characteristics of new resources. For illustrative

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46 The following environmental limits are applied to generating resources in the Energy Market modeling: SO_2 cap of 0.33 lbs/MMBtu for Connecticut and 1.20 lbs/MMBtu for rest of New England; and, NO_x cap is 0.15 lbs/MMBtu across New England. In the scenarios involving tighter environmental restrictions, these limits are further reduced over time.

47 ISO-NE PAC 09, February 15, 2006.

48 In addition, as discussed in the revised August 25, 2006 Needs Assessment, we retired all emergency generation and 50% of non-emergency generation DR that had been awarded contracts in the SWCT Gap RFP after the contracts expire in May 2008 (which means that such capacity is no longer available for the summer 2008 peak period).

purposes, the table below highlights the assumed operating and financial parameters for a gas-fired CCGT and gas-fired peaking gas turbine in 2010 and 2020.[49]

Figure 14. Modeled parameters for gas-fired CCGT and peaking gas turbine (nominal $ terms)

	CCGT		SCGT	
	2010	**2020**	**2010**	**2020**
capital cost - $/kW	$764	$905	$512	$607
average heat rate - Btu/kWh	6,370	5,995	10,290	9,685
indicative load factor	80%	80%	15%	15%
variable O&M - $/MWh	$5.0	$6.3	$4.0	$5.0
fixed O&M - $/kW/year	$21.2	$26.7	$22.3	$28.1
leverage	60%	60%	50%	50%
debt rate	9%	9%	12%	12%
after-tax required equity return	16%	16%	21%	21%
corporate income tax rate	40%	40%	40%	40%
debt financing lifetime (yrs)	15	15	10	10
capital recovery lifetime for equity portion	20	20	15	15

A new entrant is assumed to enter into the market when expected market profits (i.e. sum of energy revenues, LFRM payments and FCM payments) cover its all-in fixed costs (including its return on equity, debt charge, and FO&M). Once a new entrant has been awarded capacity in its first FCA, it is assumed to have committed to enter the market and therefore its bidding strategy changes consistent with existing resources. (i.e., in subsequent FCAs and in the LFRM, once it is built, the newly introduced generic capacity bids its minimum going forward fixed costs rather than its all-in fixed costs).

Fuel price projections: Gas price forecasts were developed using NYMEX forwards for the first five years (2007-2011) and then blended into the long-term forecast from the EIA's *Annual Energy Outlook 2006*. Sensitivities on this fuel price forecast were based on the EIA's natural gas price forecast errors over time, as highlighted in the table below.

Figure 15. Projected Boston Citygate natural gas prices under Base Case, High Case and Low Case (nominal $/MMBtu)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Base Case	$10.9	$10.5	$ 9.9	$ 9.4	$ 8.9	$ 9.1	$ 9.4	$ 9.4	$ 9.3	$ 9.4	$ 9.7	$10.2	$10.7	$11.0	$11.5
High Case	$10.9	$11.2	$11.5	$11.9	$12.2	$12.7	$13.4	$13.7	$14.6	$15.8	$16.5	$17.5	$18.4	$20.3	$22.5
Low Case	$10.9	$ 9.6	$ 8.4	$ 7.0	$ 5.6	$ 5.5	$ 5.4	$ 5.2	$ 4.0	$ 3.7	$ 3.7	$ 3.7	$ 3.7	$ 3.7	$ 3.7

The oil price forecast is based on 18 months forwards available from NYMEX. The starting point (2007) for the distillate oil forecast is based on the heating oil forwards from NYMEX. A distillate-residual differential is also applied, based on the reported differentials from *EIA*

49 Other new entrant technologies may be considered in the baseline outlook, depending on expectations about fuel prices in the various cases.

Annual Energy Outlook 2006. Each fuel oil price track is then escalated based on the implied projected rate of growth for crude oil forecasts from *EIA Annual Energy Outlook 2006*.

The coal price assumptions are based on the last 24 months' average delivered price to each plant escalated to nominal terms using the annual rate of change implied in the coal price index and inflation rate from EIA's *Annual Energy Outlook 2006*. Note that it is important to use plant specific coal price outlooks since each coal plant has different sulfur content levels and different contracts for commodity and transportation, resulting in different delivered fuel costs. For illustrative purposes, the oil price forecasts and average coal price forecasts are presented in the table below in Figure 16. In summary, gas and oil prices move together but coal and uranium prices stay the same under the various fuel price sensitivities.

All the fuel price forecasts are based on market surveys completed prior to the initial release of the draft RFP in the April 2006 - May 2006 timeframe. Fuel market dynamics have moved from that date and will continue to evolve over time. An update fuel price forecast will be published on the RFP website no later than one month before the Financial Bid deadline.

Note that the investment needs (in MW as shown in Figure 1 and Figure 2 on pages 14 and 15, respectively, of this RFP) stay the same under different fuel price scenarios. However, the choice of technology may change if the fuel price changes in the sensitivities re-set the levelized costs of different technologies.

Figure 16. Projected oil and coal prices under Base Case, High Case and Low Case (nominal $/MMBtu)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Residual Oil															
Base Case	$ 7.0	$ 6.8	$ 6.5	$ 6.2	$ 6.1	$ 6.3	$ 6.5	$ 6.6	$ 6.8	$ 6.9	$ 7.3	$ 7.5	$ 7.6	$ 8.2	$ 8.5
High Case	$ 7.0	$ 7.2	$ 7.5	$ 7.9	$ 8.4	$ 8.8	$ 9.3	$ 9.5	$10.7	$11.7	$12.3	$12.9	$13.1	$15.1	$16.6
Low Case	$ 7.0	$ 6.2	$ 5.5	$ 4.7	$ 3.9	$ 3.8	$ 3.8	$ 3.6	$ 3.0	$ 2.8	$ 2.8	$ 2.7	$ 2.6	$ 2.8	$ 2.7
Distillate Oil															
Base Case	$13.4	$13.3	$13.1	$12.9	$12.8	$13.4	$13.6	$13.8	$14.4	$14.9	$15.4	$16.1	$16.3	$17.5	$17.9
High Case	$13.4	$14.1	$15.3	$16.3	$17.5	$18.7	$19.4	$20.1	$22.6	$25.1	$26.0	$27.5	$28.0	$32.2	$35.0
Low Case	$13.4	$12.2	$11.1	$ 9.7	$ 8.1	$ 8.1	$ 7.8	$ 7.6	$ 6.3	$ 5.9	$ 5.9	$ 5.9	$ 5.6	$ 5.9	$ 5.8
Coal - New England average															
Base/ High/ Low	$ 2.3	$ 2.4	$ 2.2	$ 2.3	$ 2.3	$ 2.6	$ 2.6	$ 2.7	$ 2.7	$ 2.7	$ 2.8	$ 2.8	$ 2.9	$ 3.0	$ 3.1

Demand: The demand assumptions used in the modeling rely on ISO-NE's projections for demand under the reference case (50/50) and high and low economic cases. These forecasts were published by ISO-NE as part of RSP 2006. ISO-NE's forecast extends for ten years, while the modeling analysis will look over a longer time period in order to accommodate contract terms of up to fifteen years. For each year after 2015, the estimated load growth rate from ISO's load projection between 2006 and 2015 was applied to determine the projected demand levels in this period.

In both written comments and technical conference, stakeholders indicated a preference for the 90/10 demand forecast for assessing investment needs (and possibly the Bid Evaluation), because it is the preferred input assumption for ISO's transmission risk and reliability analysis.

By definition, the 90/10 load forecast is an extreme weather forecast - peak load under the 90/10 only has a 10% chance of being exceeded. If the 90/10 load forecast was applied in this long term modeling, an extreme weather assumption would be embedded in the Bid Evaluation. In other words, The Bid Evaluation would be assuming that New England will experience extreme weather for every year over the next 15 years. Rather than use an extreme weather forecast of peak demand, the Economic Analysis has employed the expected peak demand forecast (ISO'S Reference Case, or 50/50 demand outlook), which is consistent with the basis for ISO-NE's resource adequacy analysis (per the ICR), as well as the basic premise of long term forecasting[50]. However, in order to assess the potential for demand growth changes over time, high and low economic cases for demand growth have been included in the "baseline" modeling and Bid Evaluation.

Figure 17. Projected demand for New England and Connecticut under ISO-NE's reference case (50/50), high economic case, and low economic case, 2007 – 2021

Reference case

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ISO-NE															
Peak demand (MW)	27,380	27,905	28,560	29,190	29,890	30,530	31,030	31,495	31,905	32,499	33,106	33,723	34,353	34,996	35,651
Energy (GWh)	133,990	135,785	138,035	140,345	142,805	145,170	147,235	149,200	151,100	153,010	154,946	156,908	158,897	160,913	162,956
Growth in peak demand		*1.9%*	*2.3%*	*2.2%*	*2.4%*	*2.1%*	*1.6%*	*1.5%*	*1.3%*	*1.9%*	*1.9%*	*1.9%*	*1.9%*	*1.9%*	*1.9%*
CT (rest of CT)															
Peak demand (MW)	3,630	3,695	3,780	3,865	3,955	4,050	4,115	4,175	4,230	4,309	4,390	4,472	4,556	4,641	4,728
Energy (GWh)	17,105	17,320	17,600	17,915	18,235	18,565	18,825	19,080	19,310	19,564	19,821	20,081	20,345	20,612	20,883
Growth in peak demand		*1.8%*	*2.3%*	*2.2%*	*2.3%*	*2.4%*	*1.6%*	*1.5%*	*1.3%*	*1.9%*	*1.9%*	*1.9%*	*1.9%*	*1.9%*	*1.9%*
SWCT															
Peak demand (MW)	3,650	3,720	3,805	3,895	3,990	4,070	4,125	4,175	4,225	4,301	4,378	4,457	4,537	4,618	4,701
Energy (GWh)	17,190	17,415	17,715	18,040	18,370	18,650	18,860	19,065	19,250	19,486	19,726	19,968	20,214	20,462	20,714
Growth in peak demand		*1.9%*	*2.3%*	*2.4%*	*2.4%*	*2.0%*	*1.4%*	*1.2%*	*1.2%*	*1.8%*	*1.8%*	*1.8%*	*1.8%*	*1.8%*	*1.8%*

High economic case

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ISO-NE															
Peak demand (MW	27,579	28,512	29,419	30,326	31,295	32,186	32,952	33,678	34,356	35,272	36,214	37,181	38,174	39,194	40,242
Energy (GWh)	136,654	140,393	143,969	147,583	151,338	154,987	158,342	161,586	164,753	168,279	171,883	175,565	179,328	183,173	187,102
Growth in peak demand		*3.4%*	*3.2%*	*3.1%*	*3.2%*	*2.8%*	*2.4%*	*2.2%*	*2.0%*	*2.7%*	*2.7%*	*2.7%*	*2.7%*	*2.7%*	*2.7%*
CT (rest of CT)															
peak demand (MW	3,646	3,756	3,865	3,978	4,096	4,215	4,307	4,395	4,477	4,588	4,703	4,820	4,940	5,063	5,189
energy (GWh)	17,387	17,801	18,221	18,662	19,104	19,564	19,950	20,326	20,695	21,112	21,537	21,970	22,412	22,863	23,324
Growth in peak demand		*3.0%*	*2.9%*	*2.9%*	*3.0%*	*2.9%*	*2.2%*	*2.0%*	*1.9%*	*2.5%*	*2.5%*	*2.5%*	*2.5%*	*2.5%*	*2.5%*
SWCT															
Peak demand (MW	3,666	3,778	3,891	4,008	4,130	4,240	4,320	4,395	4,466	4,574	4,684	4,797	4,913	5,031	5,153
Energy (GWh)	17,476	17,902	18,335	18,790	19,246	19,657	19,992	20,314	20,629	21,026	21,432	21,845	22,266	22,695	23,133
Growth in peak demand		*3.1%*	*3.0%*	*3.0%*	*3.0%*	*2.7%*	*1.9%*	*1.7%*	*1.6%*	*2.4%*	*2.4%*	*2.4%*	*2.4%*	*2.4%*	*2.4%*

50 ISO-NE uses the 50/50 demand forecast in its determination of ICR. Therefore, the 50/50 forecast is the appropriate demand forecast to use in the Needs Assessment. It comes down to a question of costs. Is the state willing to pay for enough capacity in order to avoid even occasional OP4 emergency action costs? Because we are seeking reduction in FMCCs, it is appropriate for the state to plan and build to the economic needs rather than the reliability needs in order to provide the maximum cost protection to consumers. However, that is not to say that there will be no reliability improvements. Since we are adding new or incremental capacity, we expect reliability improvements.

Figure 17 continued

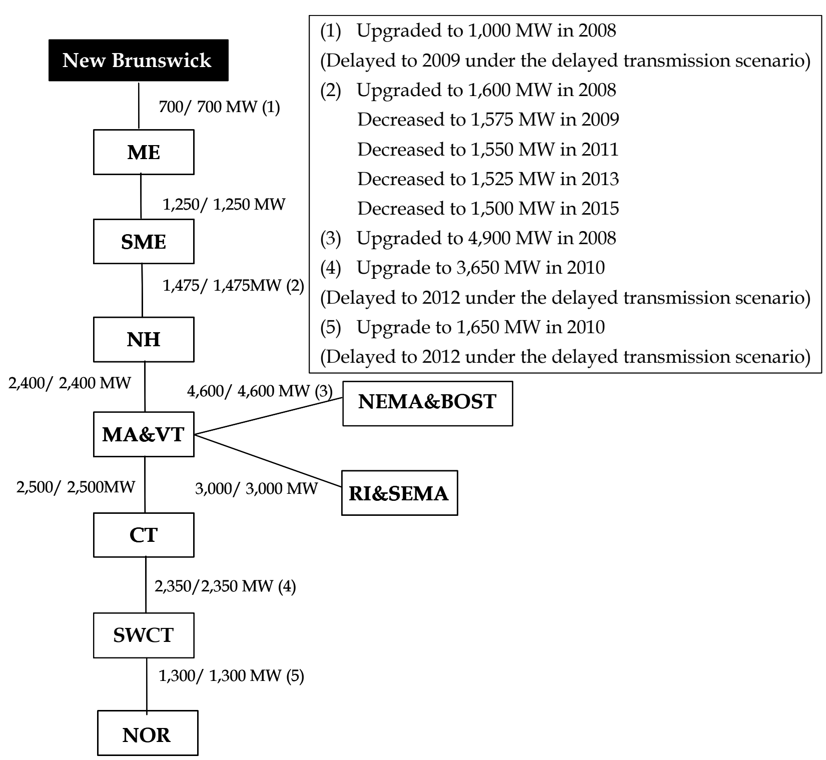
Low economic case

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ISO-NE															
Peak demand (MW	27,131	27,278	27,643	28,029	28,465	28,833	29,070	29,271	29,413	29,708	30,007	30,309	30,616	30,926	31,241
Energy (GWh)	131,297	131,144	132,054	133,133	134,328	135,451	136,252	136,967	137,583	138,027	138,477	138,931	139,389	139,853	140,321
Growth in peak demand		*0.5%*	*1.3%*	*1.4%*	*1.6%*	*1.3%*	*0.8%*	*0.7%*	*0.5%*	*1.0%*	*1.0%*	*1.0%*	*1.0%*	*1.0%*	*1.0%*
CT (rest of CT)															
peak demand (MW	3,610	3,635	3,688	3,749	3,813	3,878	3,915	3,949	3,974	4,021	4,070	4,118	4,167	4,217	4,268
energy (GWh)	16,822	16,825	16,978	17,170	17,356	17,557	17,683	17,809	17,911	18,010	18,111	18,211	18,312	18,414	18,516
Growth in peak demand		*0.7%*	*1.5%*	*1.7%*	*1.7%*	*1.7%*	*1.0%*	*0.9%*	*0.6%*	*1.2%*	*1.2%*	*1.2%*	*1.2%*	*1.2%*	*1.2%*
SWCT															
Peak demand (MW	3,629	3,657	3,714	3,778	3,845	3,899	3,926	3,950	3,964	4,008	4,053	4,098	4,144	4,190	4,237
Energy (GWh)	16,908	16,921	17,084	17,288	17,486	17,641	17,719	17,799	17,854	17,938	18,022	18,107	18,192	18,278	18,364
Growth in peak demand		*0.8%*	*1.6%*	*1.7%*	*1.8%*	*1.4%*	*0.7%*	*0.6%*	*0.4%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*	*1.1%*

Source: ISO-NE CELT 2006; Note that figures in blue reflect calculated estimates based on ISO-NE forecast growth rates.

Internal Transmission Interfaces: Thermal transfer limits between key regions of ISO-NE were based on the latest available data from ISO-NE, as summarized in Figure 18 below. In addition, transmission losses were incorporated in the Energy Market modeling. Marginal transmission loss factors were calculated by dividing the historical hourly real time loss component by the energy component of LMP by RSP zone relative to Mass Hub for 2005. These loss factors were then averaged across the year for each of the sub-regions modeled and applied in the Energy Market modeling.

Figure 18. Modeled topology and thermal transfer limits between sub-regions in ISO-NE's control area



Source: ISO-NE RSP 2006

Transmission expansion is assumed to proceed according to the most recent estimates from ISO-NE (RSP 2006). However, the effects of delays of one to two years to known transmission expansion projects, such as Northeast Reliability Interconnect Project and SWCT Reliability Project Phase 2, will also be simulated in the sensitivities. The Southern New England Transmission Reinforcement (SNETR) proposal is not incorporated in the Economic Analysis at this time because it is still a conceptual project, rather than a known and approved transmission project. If the status of SNETR becomes refined prior to the Qualifications Bid deadline, the Economic Analysis assumptions will be updated accordingly and posted on the RFP website.

5.5.2 Other Factors

A total of 15% of the Final Project Score in the Bid Evaluation will be determined through the assessment of other criteria described in the EIA, collectively referred to as Other Factors. Five categories of Other Factors have been identified and incorporated into the Bid Evaluation process, as summarized in the figure below.

Based on the project details specified by Bidders in the Bid Submissions, as well as the modeling results, projects will be assigned points for each of these five Other Factors, which will complement their Economic Analysis (i.e., the NPV of the net benefits). These points will be strictly additive. There will be no deduction of points for not qualifying for an Other Factor.

Although certain of these secondary criteria, such as the benefits of fuel diversity, a preference for Brownfield sites, and the costs of environmental emissions, are already represented in the economic assessment (see below), they will also be incorporated into the Other Factors category of the Bid Evaluation in response to overwhelming stakeholder comment on the importance of having these factors analyzed outside the Economic Analysis.

How have other criteria been incorporated into the Economic Analysis?

Fuel diversity: The benefits of fuel diversity will be assessed by modeling a scenario that assumes a high level of demand and a natural gas shortage, translating into lower than expected generation from pipeline-fueled natural gas fired facilities. This scenario will capture the potential costs to ratepayers of a lack of fuel diversity.

Existing sites and infrastructure: It is reasonable to expect that projects that use of existing sites and infrastructure will ultimately face lower development costs, which should be reflected in a lower bid price for such projects. In addition, projects that use existing sites typically face lower project execution risk, which will be assessed separately, as discussed later in this section.

Environmental issues: The impact of environmental emissions is directly factored into the economic modeling. The expected costs of mitigating (with additional capital expenditure) or buying allowances for sulfur dioxide (SO_2), nitrogen oxide (NO_X), and carbon dioxide (CO_2), and the impact of tightening environmental regulation on retirement decisions and new entry costs, is reflected in the projected costs to load. Allowance costs are incorporated into the Energy Market prices, while capital expenditure decisions are reflected in the economic retirement and new entry decisions. Thus, the major, direct costs of environmental compliance are part of the cost-benefit analysis.

In total, the Other Factors represent 15% of the Bid Evaluation or Final Project Score. The point system applied to each of the Other Factors is based on the weighting of each category (as described by the Percentage Value assignment in the figure below). Each of the five Other Factors is described in more detail below.

Figure 19. Overview of Other Factors

Criteria	Percentage Value	
Reduction in emissions of SO_2, NOx, and CO_2	*5.0%*	
Use of existing sites and infrastructure	*2.5%*	
Benefits of fuel diversity	*2.5%*	
Front-loading of costs	*2.5%*	
Other benefits	*2.5%*	
Other Factors		**15%**

- **Reduction in emissions in SO_2, NOx, and CO_2:** Through the modeling of Energy Market dynamics in New England, plant dispatch profiles and fuel consumption will be forecasted. There is also extensive data on emissions rates for all major generators in New England (from the EPA CEMS database). Based on this information, it is possible to measure the change in SO_2, NO_X, and CO_2 emissions resulting from each project on an annual basis across the New England market (each pollutant will be treated equally on a quantity per kW of installed capacity (tons/kW) basis). Projects that result in a decrease in environmental emissions will receive a maximum of 5.0 points under the Other Factors scoring approach (representing the 5% weighting factor for this category in the Final Project Score). The aggregated stream of emission reductions over the Contract Term for each proposed project will be used to establish the range of emissions reductions across all proposed projects. Each project's percentile rank in this range will then determine its allotment of points:
  - Projects in the top 16.67th percentile in total reduction in emissions (on a ton per kW basis) will be allocated 5 points,
  - Projects in between the 16.67th and 33.33th percentile in total reduction in emissions (on a ton per kW basis) will be allocated 4 points,
  - Projects in between the 33.33th and 50th percentile in total reduction in emissions (on a ton per kW basis) will be allocated 3 points,
  - Projects in the between the 50th and 66.67th percentile in total reduction in emissions (on a ton per kW basis) will be allocated 2 points,
  - Projects in between the 66.67th and 83.33th percentile in total reduction in emissions (on a ton per kW basis) will be allocated 1 point; and,
  - Projects that do not reduce emissions will be allocated 0 points.
- **Use of existing sites and electric generation-related infrastructure:** Projects that are sited on existing electric generation sites will receive up to 2.5 points under the Other Factor scoring system in their Final Project Score (based on the 2.5% weighting factor for this

category). Those facilities sited on locations that already possess electric generation infrastructure, and those projects that do not require such infrastructure (i.e., energy efficiency, conservation, and demand response projects), will receive 2.5 points. Projects on sites with certain existing supply infrastructure, like fuel supply and transmission infrastructure, but no generation infrastructure, will receive 2 points. Projects that rely exclusively on existing transmission (for example, use of the new transmission lines being built in SWCT) or generation infrastructure will receive 1 point. Projects that are using sites that have never been developed in the past for purposes of electric generation and will require new transmission or fuel supply infrastructure will be allocated 0 points.

- **Benefits of fuel diversity:** Based on the technical parameters of the project specified in the Bid Submission, projects may be allocated up to a maximum of 2.5 points under the Other Factors scoring approach for fuel diversity (based on the 2.5% weighting assigned to this category in the Bid Evaluation). More specifically, renewable projects, demand response, energy efficiency, and conservation projects will be granted 100% of the maximum possible points, or 2.5 points, for this category. Other non-natural gas fired plants will be granted 1.25 points, while power plants that are using gas as their primary fuel source will receive 0 points.

- **Front-loading of costs:** Projects that reasonably allocate their costs in line with expected benefits (as measured by whether or not the net benefit in a given year is negative) will receive up to 2.5 points (based on the 2.5% weighting for this criteria). Based on the Economic Evaluation, a project with positive annual net benefits in the initial five years of its Contract Term will be allocated 2.5 points. Projects with annual net benefits negative for one year of the initial five years of its Contract Term will be allocated 2.0 points. Projects with annual net benefits negative for two years of the initial five years of its Contract Term will be allocated 1.5 points. Projects with annual net benefits negative for three years of the initial five years of its Contract Term will be allocated 1.0 point. Projects with annual net benefits negative for four years of the initial five years of its Contract Term will be allocated 0.5 points. Projects with annual net benefits negative for five years of the initial five years of its Contract Term will be allocated 0 points.

- **Other benefits:** The DPUC will also grant additional points (up to a maximum of 2.5 points) for other benefits that a project can produce for the benefit of UI and CL&P ratepayers. These points will be based on review of the project-specific information provided by the Bidder and specific evidence that the Bidder will provide demonstrating such benefits will exist. Such other benefits might include, but are not limited to, a project's impact on improving the reliability of the transmission network[51], reducing local unemployment, increase local tax revenues, eliminate the need for existing long term RMRs[52], projects with very high levels of efficiency (such as Combined Heat and Power), etc.

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[51] For example, Demand Response and ODR projects located in Southwest Connecticut could argue that they will contribute to reliability in a highly congested area.

[52] To obtain credit for this, Bidders will have to articulate how their project displaces existing RMRs, and explicitly and concretely cite the various reliability-driven factors which resulted in an existing RMR (or RMRs) and how the proposed project would relieve those factors, referring, where applicable, to the basic factors cited by ISO-NE in its decision(s) approving existing RMRs.

Once the total score for the Other Factors is established for all proposed projects, that score will be weighed on an approximately 15% to 85% basis with the Economic Analysis (i.e., NPV projections) for each proposed project in the Final Project Scores.

5.5.3 Project execution risk

All projects will separately be assessed for project execution risk, which refers to the likelihood that projects will not come on-line at the date specified in their proposal and based on the technical terms specified for the project in the Bid Submission. The DPUC will analyze various factors including: current status of site control and environmental and site permitting; the expected ease of remaining environmental and site permitting; the likelihood of securing financing; construction risk; and operating risk (e.g. fuel supply risk and whether the project is using commercially proven technology or a new technology without operating history, etc.). Projects will be assessed in a comparative manner in terms of project execution risk. That is, those projects that have the highest level of project execution risk will be ranked the lowest while those projects that have the lowest level of project execution risk will be ranked the highest.

5.5.4 Portfolio assessment and winning project selection

The DPUC will then consider the proposed projects based on the Final Project Scores (consisting of the Economic Analysis and Other Factors) and project execution risk. The DPUC will select as preliminary winners those projects that achieved the highest Final Project Score while having the lowest project execution risk.

Because it is likely that the DPUC will be accepting a portfolio of projects, the DPUC will also conduct analyses to ensure that the aggregated portfolio of the preliminary winning projects has a positive net benefit (NPV) for ratepayers. As such, the portfolio modeling stage of analysis will include a detailed simulation of the combined impact of the different projects on costs to Connecticut load in order to identify any substitution effects which diminish the marginal benefits of each project.

Once the portfolio analysis has been completed, the DPUC will also test the market power implications of the winning portfolio for the ISO-NE Energy Market (winning projects will effectively be price takers in the FCM and LFRM based on the contract terms, and would therefore, by definition, not increase market power in those markets). The DPUC will test the Herfindahl-Hirschman Index (HHI)[53] concentration level of the ISO-NE Energy Market, an approach commonly applied in economics and required by FERC Order Nos. 592 and 642), to ensure that the selection of the projects does not result in an overly concentrated Energy Market, based on the guidelines used by the Department of Justice and FERC.[54] Although the

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53 The HHI is an analytical approach that can be used not only to assess the current level of concentration in the market, achieved by adding the squared market shares of every market participant together.

54 The Department of Justice *Merger Guidelines* lay out three ranges of market power concentration: an unconcentrated post-transaction market, which is indicated by an HHI below 1,000; a moderately concentrated post-transaction market, which is indicated by an HHI ranging from 1,000 to 1,800; a highly concentrated post-transaction market, which is indicated by an HHI above 1,800. The level of HHIs is further supplemented by the change in HHIs to determine whether a transaction raises competitive market

Contracts are expected to reduce, rather than amplify, the incentive for strategic behavior, the DPUC will also re-run the energy market model with the selected projects, relaxing the competitive bidding assumption, to assess whether the market structure changes resulting from the award of Contracts increases any market participant's ability to bid strategically in the market. Any proposed project (or projects) that increase market concentration above the levels allowed by the Department of Justice or that amplify a market participant's ability to withhold from the Energy Market will not be selected.

After the market power analysis has been completed, the DPUC will select final winning projects, which individually and in the aggregate, will result in positive net benefits to Connecticut ratepayers over the long run.

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concerns. A change in HHI below 100 combined with a post-transaction HHI below 1,800 is acceptable. A change in HHI below 50 combined with a post-transaction HHI of above 1,800 is also acceptable.

6 Appendices

6.1 Appendix A: Glossary

For a full list of applicable definitions, please see Article 1 of the Contract templates.

6.2 Appendix B: List of Acronyms

CL&P – Connecticut Light & Power

DPUC – Connecticut Department of Public Utility Control

EIA – Energy Independence Act

EPC – Engineering Procurement Contract

FERC – Federal Energy Regulatory Commission

FCA – Forward Capacity Auction

FCM – Forward Capacity Market

FMCC – Federally Mandated Congestion Charges

ICR – Installed Capacity Requirement for New England in the FCM

ISO or ISO-NE – Independent System Operator of New England

LFRM – Locational Forward Reserve Market

LFRR – Locational Forward Reserve Requirement

LMP – Locational Marginal Price

LSR – Local Sourcing Requirement for a Capacity Zone in the FCM

MCP – Market Clearing Price

NPV – Net Present Value

ODR – Other Demand Resource

RFP – Request for Proposal

RMR – Reliability Must Run contract

UI – The United Illuminated Company

6.3 Appendix C: DPUC procurement principles and standards

Approved Principles and Standards to be Used for Developing and Issuing Requests for Proposals Under Section 12 of Public Act 05-01, June Special Session

Principles:

1. As broad a group as is practicable must be notified and offered an opportunity to respond to the procurement inquiry or request.

2. Procurement should be conducted in a manner to cost-effectively promote price consistency and stability and minimize revenue requirements over the long term while also balancing the need to further certain non-economic policy objectives.

3. Consistent with applicable law, non-discriminatory and timely access to relevant data and information shall be provided by the entity conducting the RFP in a manner designed to maximize the number of responses.

4. The procurement process should not be conducted in a manner that, and the contracts produced from the procurement process should not contain terms that, will limit the Department, the distribution companies, or any other entities from pursuing demand-side strategies or promoting renewable energy procurement policies of the State.

5. In order to maximize the value each bidder offers, the procurement process should provide the Department with flexibility in structuring and requesting bids that allows bidders flexibility in a manner consistent with, and that does not undermine, the Department's ability to meaningfully, compare bid responses based on clear standards.

6. The procurement process should produce contracts that minimize the risk or impact of non-performance by the winning bidders.

7. The request for proposal shall be designed to give effect to the methodology, if any, approved in Docket No. 05-07-18, DPUC Investigation into the Financial Impact of Long Term Contracts on Electric Distribution Companies, to compensate the distribution companies for any negative impacts on the financial conditions of the distribution companies.

Standards:

1. The procurement process, including the request for proposals, shall be designed and the process conducted in a manner to:

    1) Procure measures that result in the greatest aggregate reduction of federally mandated congestion charges, including, but not limited to, locational marginal pricing, Reliability Must Run contracts, summer emergency capacity resources (GAP RFP), and generation capacity and reserve payments, for the period commencing on May 1, 2006, and ending on December 31, 2010, or such later date specified by the Department.

2) Make efficient use of existing energy/utility facility sites and supply infrastructure;

3) Serve the long-term interests of electricity ratepayers;

4) Encourage diversity in the fuel mix, technology and resources used in generation in the state;

5) Result in the lowest reasonable cost of such products and services;

6) Procure measures that are consistent with, and in furtherance of, any energy plans and infrastructure criteria guidelines developed by the Connecticut Energy Advisory Board in effect at the time the procurement process is conducted;

7) Increase electric system reliability;

8) Procure measures consistent with the principles of General Statutes of Connecticut § 16-19e(a)(1) through (3);

9) Procure measures that comply with all applicable state laws, including environmental laws; and

10) Comply with all of the requirements mandated by Section 12 of Public Act 05-01, June Special Section.

2. The procurement process, including the request for proposals, shall be designed and the process conducted in a manner best suited to attract bids from a diversity of measures identified in the legislature, to wit: (1) customer-side distributed resources, (2) grid-side distributed resources, (3) new generation facilities, including expanded or re-powered generation, and (4) contracts for a term of no more than 15 years between a person and an electric distribution company for the purchase of electricity capacity rights.

3. Any proposals submitted by an electric distribution company shall include its full projected costs such that any projected costs recovered from or defrayed by ratepayers are included in the projected costs and shall demonstrate to the satisfaction of the department that its bid is not supported in any form through cross subsidization by affiliated entities or by any aspect of the utility's transmission or distribution business.

6.4 Appendix D: Bidder Registration Form

Electronic writable PDF of this form is available on the RFP website.

Company Name:	
Company Address:	
Contact Name and Title:	
Contact Phone #:	
Contact Fax #:	
Contact E-Mail Address:	
Project Name:	
Type of Project (technology): **(please note if multiple)**	
Selected Contract type (select one):	☐ **Generation Contract** ☐ **Demand Response Contract** ☐ **ODR Contract (Conservation, Energy Efficiency, or Distributed Resources)**
Project Capacity (MW):	
Contract Quantity (MW), please note changes, if any, over Term:	
Project Commercial Operation Date: **(please note if this is staggered)**	

Project Location: **(please note if multiple)**	
Expected Point of Interconnection: **(Please note if multiple)**	

6.5 Appendix E: Introduction to Bidder Team

Electronic writable PDF of this form will be available on the RFP website.

Bidder's Name:	
Bidder's Address:	
Contact Name and Title:	
Contact Phone #:	
Contact Fax #:	
Contact E-Mail Address:	
Federal Tax ID:	
DUNS #:	
Legal Structure (please check all that apply):	**( ) Corporation [( ) Single Entity or ( ) Parent or ( ) Subsidiary]** **( ) Division of a Corporation** **( ) Proprietorship** **( ) Partnership (please specify form __________)**
State of Residency or Organization:	
Date of Incorporation or Date Business Started:____________________	
List of Affiliates:	

6.6 Appendix F : Minimum Technical Requirements – Experience of Bidder

Please fill in the following form for each key member of the Bidder Team. In addition, provide a resume for each Bidder Team Member.

Name of Bidder Team Member:	
Area of Specialization:	
Length of experience:	
Description of experience:	
Anticipated role in this project:	

In addition, please also provide the following information:

- the names of every member of the Bidder Team and a short description of their role regarding the development, construction, operation, and delivery of the proposed project; and
- an organizational chart that provides a schematic representation of ownership and contractual links among all entities or individuals involved in the development, construction, financing, and operation of the project.

6.7 Appendix G: Financial Questionnaire

The Bidder should submit the following information as part of the financial questionnaire to demonstrate its financial stability and viability:

- Most recent two years' audited financial statements (from Annual Report, 10 K, 10Q, or other); and
- Company Credit Rating from Standard & Poor's, Moody's, or Fitch. Information should include the last rating date and the senior unsecured long term debt rating; and
- Bank reference information, including contact name, telephone number, and account number.

6.8 Appendix H: Project Description Questionnaires

Please also refer to the Project Technical Templates attached in Microsoft Excel format.

6.8.1 Appendix H-1: Project Description Questionnaire for Generation projects

Part 1: Executive Summary

Provide a short description of the plant and equipment to be used in the proposed project, including the technology, project design, location of such plant and equipment, as well as the proposed Commercial Operation Date of the facility. This description should not exceed one page in length. In addition, please complete form H1-A Proposal Summary attached in Microsoft Excel format.

Part 2: Project Eligibility

Please respond to the following questions.

1. Please describe how the project qualifies for this procurement process per the EIA?

2. Is the project electrically located in the state of Connecticut? Please provide all relevant supporting documents.

3. Is the projected expected to qualify to meet Connecticut's LSR? Please provide all relevant supporting documents.

4. Is the project's electrical output deliverable in the state of Connecticut? Please provide all relevant supporting documents.

5. Does the project constitute new or incremental capacity as compared to the 2006 ISO-NE CELT Report?

2. If this project includes a refurbishment or re-powering of an existing (or currently deactivated) facility, please describe how this project qualifies for this RFP. In addition, please confirm whether the Bidder for this project is also the operator of the existing facility.

3. What amount of capacity (MW) from the summer demonstrated capacity (not previously listed in the 2006 CELT report) is being bid into this procurement process?

4. Please describe why the project is technically and operationally capable of participating in ISO-NE's FCM and/or LFRM? Are there any other ISO-NE Markets that this project anticipates being able to participate in?

Part 3: Project specifications

1. What is the project name?

2. What is the project's proposed location? Please provide a map showing the location of the project site in relation to neighboring roads and lands, drawn to a scale of no more than 1:10,000 and no less than 1:100,000, and having a size of at least six inches by six inches. Please provide a survey or its equivalent delineating the boundaries of the lands for the site, including any easements appurtenant to such lands and scale parameters for the survey.

3. What is the status of equipment purchase?

4. What is the project's anticipated (Target) Availability on an annual and seasonal basis?

5. List all fuel(s) consumed by the proposed facility as a primary fuel. List any other fuels consumed by the proposed facility (backup and emergency).

6. If available, provide information about how fuel will be supplied and transported to the facility. Please include a description of how the project will secure and store 5 days worth of emergency backup fuel supply. (Note that there are also requirements for maintaining adequate reserves of secondary fuels for gas fired facilities, as described in the Generation Contract.)

7. In addition, please complete Forms H1-B through H1-E attached in Microsoft Excel format.

Part 4: Siting, permitting, and environmental issues

1. Please provide documentation to demonstrate control of the site, if such control has already been established. Such documentation might include a registered transfer, lease, license, or other agreement permitting the use of the land for the site; written agreement to purchase the land; or written agreement entitling the Bidder to an option to purchase, lease, license, or use the site.

2. Has the project already been submitted to the Connecticut Siting Council for approval? If so, provide docket name and status? If not, what are plans for this process?

3. In addition please complete form H1-F and form H1-G and form H1-H attached in Microsoft Excel format.

Part 5: Interconnections

Bidders also need to submit Attachment A: Technical data required for System Impact Study which they have or will be providing to ISO-NE as part of the Interconnection request, if relevant

1. What is the project's point of interconnection to the electricity network? Please provide a single line electrical drawing (if available) which identifies the point where the project will interconnect, illustrating regional transmission and distribution facilities.

2. Is this a transmission system, local distribution system, or end-user connection point?

3. Has the project been submitted to ISO-NE's Interconnection Queue, and if so, what is the status of this submission? If the project has been granted an Interconnection Agreement, what is the status of building the interconnection?

4. If no report is yet available from ISO-NE on the project's interconnection, please provide any and all relevant documentation including reports by project engineers or consultants assessing the project's interconnectability into the New England system and its deliverability into the state of Connecticut.

Part 6: Major project milestones

Please provide milestone dates for the following events. Please note that starred milestone events will be used in calculating liquidated damages under the Contract should the milestone dates be missed. Please refer to the Generation Contract for further details.

Milestone Event	Milestone Date
Permanent Site Control achieved*	
Major permits applied for, including ISO-NE Interconnection Study, CSC, DEP, and others as applicable	
Major permits obtained, including receipt of approvals from the ISO, CSC, DEP, and FERC, as applicable	
Engineering, equipment procurement, and construction contract(s) executed	
Financial closing*	
Interconnection Study completed	
Equipment Ordered	
Major Equipment Delivered	
Commencement of Construction*	
Foundations laid	
Interconnection completed	
Completion of Major Construction – Ready for Testing	
Commercial Operation*	

6.8.2 Appendix H-2: Project Description for Demand Response projects

Part 1: Executive Summary

Please provide a short description of the control equipment to be used in the proposed DR and DSM project, including the technology, project design, location of such plant and equipment, as well as the proposed Commercial Operation Date of the project. This description should not exceed one page in length.

Part 2: Project Eligibility

Please respond to the following questions.

1. Is the project already or going to be electrically located in the state of Connecticut? Please provide details.

2. Is the projected expected to qualify to meet Connecticut's LSR? Please provide all relevant supporting documents.

3. Will this project be a dispatchable demand resource and qualify for the LFRM?

4. Is the project currently (as of September 1, 2006) participating in any DPUC or ISO-NE programs for demand response or demand side management? If so, please list all programs and describe when contract or current funding sources expire?

5. What amount of capacity (MW) is being bid into this procurement process? Note that this capacity figure should be equal to the Contract Quantity, as defined in the Demand Response Contract, as well as the amount that ISO-NE currently recognizes for a Demand Response asset participating in the FCM.

6. Please describe why the project is technically and operationally capable of participating in ISO-NE's FCM? Is this project technically and operationally capable of participating in ISO-NE's LFRM or reasonably expected to participate at some point during the proposed Term of Contract in ISO-NE's LFRM? Are there any other ISO-NE Markets that this project anticipates being able to participate in? If so, please describe.

Part 3: Project specifications

1. What is the project name?

2. What is the project's proposed location(s)? Please provide a map showing the location(s) of the site(s) providing demand response.

3. What is the status of Control Equipment purchases, if required?

4. What is the project's anticipated Performance Rate on an annual and seasonal basis?

5. Please complete Forms H2-A through H2-H attached in Microsoft Excel format.

Part 4: Major project milestones

Please provide milestone dates for the following events. Please note that starred milestone events will be used in calculating liquidated damages under the Demand Response Contract should the milestone dates be missed. Please refer to the Demand Response Contract for further details. Note of these dates vary for different subsets of the Contract Quantity that a separate table should be completed for each grouping with the capacity for each group clearly specified.

Milestone Event	Milestone Date
Complete design of project*	
DR Project Approvals, Site Approvals and Permitting *(Applicable only if the Control Equipment includes a generator)*	
Completion of connection assessments (including receipt of approvals from ISO-NE, LDC, or Load, as applicable.)	
Engineering, equipment procurement and construction contracts executed *(Applicable only if the Control Equipment includes a generator)*	
Financial Closing	
Equipment Order	
Major Equipment Delivered*	
If the DR Project requires the participation of third party loads, delivery to the Buyer of a certificate addressed to it from the DR Verification Consultant, stating that the Supplier has executed DR Third Party Agreements as collectively represent 80% of the Contract Quantity, which shall occur no later than one year prior to the milestone for Commercial Operation.*	
Commencement of Construction (as applicable)	
Completion of Construction (as applicable)	
Connection of Control Equipment to the Load*	
Initial test of project operation	
Receipt of ISO-NE certification that Project satisfies its requirements for market participation	
Receipt of independent consulting engineer certification that project operates as designed	
Commercial Operation*	

6.8.3 Appendix H-3: Project Description for ODR projects (Conservation, Energy Efficiency, and other applicable resources)

Part 1: Executive Summary

Please provide a short description of the project, including the technology, project design, location of such plant and equipment, as well as the proposed Commercial Operation Date of the project. This description should not exceed one page in length.

Part 2: Project Eligibility

Please respond to the following questions.

1. Is the project already or proposed to be located in the state of Connecticut?

2. Is the project currently (as of September 1, 2006) participating in any DPUC or ISO-NE projects for conservation or load management? If so, please describe the programs and when the current funding source expires?

3. What amount of capacity (MW) is being bid into this procurement process? Note that this capacity figure should be equal to the ODR Demand Reduction Value, as defined in the ODR Contract. This figure will be adjusted to account for the avoided peak demand transmission and distribution losses and ICAP Reserve Margin, if applicable, for settlement purposes in the ODR Contract and for Bid Evaluation.

4. Is the project technically and operationally capable of participating in ISO-NE's FCM? Are there any other ISO-NE Markets that this project anticipates being able to participate in? If so, please provide details.

Part 3: Project specifications

1. What is the project name?

2. What is the project's proposed location(s)? Please provide a map showing the location(s) of the ODR projects.

3. What is the project's technology or technologies?

4. Please complete Forms H3-A through H3-H attached in Microsoft Excel format.

(continued on the next page)

Part 4: Major project milestones

Please provide milestone dates for the following events. Please note that starred milestone events will be used in calculating liquidated damages under the ODR Contract should the milestone dates be missed. Please refer to the ODR Contract for further details. Note of these dates vary for different subsets of the Contract Quantity that a separate table should be completed for each grouping with the capacity for each group clearly specified.

Milestone Event	Milestone Date
Complete design of project*	
Financial Closing, if applicable	
Order of major equipment completed	
Equipment delivery completed	
Initial test of project operation satisfactorily completed*	
Receipt of ISO-NE certification that Project satisfies its requirements for market participation (if applicable)	
Receipt of independent consulting engineer certification that project operates as designed	
Completion of ODR project performance testing, if applicable	
Commercial Operation*	

6.9 Appendix I: Anticipated Project Financing Questionnaire

Bidders are required to complete this Questionnaire in full, including the attachment of additional documents where requested.

1. Describe the proposed method of financing the project during each of the development, construction, and operating phases, including a description of: capital structure, sources of equity and debt financing including any guarantor support; form of equity financing; and the lead arranger or under writer for the required debt/equity, if applicable.

2. For each source of financing, please fill out the table below. Loans from affiliated entities, project partners, and loads that are subordinated to the primary or senior project financing should be reported as equity.

3. Describe the status of efforts to obtain equity and debt financing. If in possession of commitment letters, please attach to this document.

4. For all debt financing, please provide information as to the amount of each loan, its term, the conditions, and an amortization schedule, if available.

5. Describe whether projects are receiving any ratepayer funding for this project from the Connecticut Clean Energy Fund or the Connecticut Conservation and Load Management Fund and if so state the amount. Note that this funding will be considered as a cost in the cost benefit analysis.

Name of Entity Providing Financing:	
Type of Financing (i.e., equity, debt (senior and junior), etc.):	
Amounts of Funds to be provided:	
Status of obtaining commitment letters:	

6.10 Appendix J: Financial Bid templates

Electronic writable PDF formats will be available on the RFP website.

6.10.1 Appendix J-1: Financial Bid template for Generation or Demand Side Response projects

OVERVIEW

The Bidder agrees that the Contract Quantity denoted below will participate in the following ISO-NE Markets (only check items that apply) once it has reached Commercial Operation or is otherwise designated as a qualifying resource by ISO-NE:

a. Forward Capacity Market: _________

b. Day-Ahead Energy Market: ________

c. Real-Time Energy Market: _________

d. Locational Forward Reserve Market: _____________

   i. If item d. above is checked, what Quantity (MW)?

   ii. Is Bidder expecting project to participate in both the summer and winter auctions? (Yes or No)

CAPACITY CONTRACT:

The Annual Contract Prices in this Agreement will be settled against (only one option can be marked as selected):

- Option 1: ______ the Market Price in the FCM only
- Option 2: _______the Market Price in the FCM and the LFRM (the LFRM, in this case, represents the market clearing price net of FCM payments)

Please fill in the following table for appropriate years of the proposed Contract Term and Contract Prices depending on whether Option 1 or 2 was selected. If Option 2 was selected above, Annual Contract Prices must be provided for both the FCM and the LFRM. The Bidder may opt to settle against the LFRM (Option 2) for select years of the Contract Term. The Bidder may also choose to have different Contract Quantities for settlement purposes for LFRM and FCM under Option 2.

***** THIS TABLE MUST BE COMPLETED TO**

PARTICIPATE IN THE PROCUREMENT PROCESS ***

Contract Year	**Annual Contract Price ($/kW) for FCM**	**Annual Contract Price ($/kW) for LFRM** **(net of FCM)**	**Contract Quantity (MW)**	**Alternative Contract Quantity for LFRM (MW), at option of Bidder**

If the Project entails a de-activated asset, please provide the date of asset replacement or refurbishment ___________________________.

If the Project entails a refurbished or repowered asset, please state the number of years that the Bidder commits to maintain net increase in capacity at site_______________________.

** AT BIDDER OPTION ***

CAPACITY CONTRACT CALL OPTION:

Is the Bidder electing the Call Option? (Yes or No): ____________[55]

Strike Price ($/MWh): ___________

Please supply an index against which Strike Price will be indexed (starting the day that winning projects are approved): *(Bidders may refer to publicly available indices, such as ISO-NE's fuel price index for the LFRM or the U.S. Consumer Price Index, or may provide at the time of the Financial Bid submission a customized index showing the year-on-year percentage change desired.)*

Call Option pricing: Please fill in table below (for all years of the Contract Term).

Contract Year	Call Option Contract Quantity (MW)[56]	Call Option - Supplemental Capacity Payment ($/kW)	Alternative Annual Contract Price ($/kW) for FCM[57]

55 The DPUC reserves the right to accept the Capacity Contract with or without the Call Option.

56 This cannot exceed the Contract Quantity specified earlier in Appendix J-1 for the Capacity Contract.

57 Bidders can specify an alternative Annual Contract Price for the FCM if it chooses to bid for the Call Option, as the DPUC recognizes that contracting on the Call Option may change a Bidder's expectation regarding its expected energy profits within the Capacity Contract.

6.10.2 Appendix J-2: Financial Bid template for ODR projects

OVERVIEW

The Bidder agrees that the Contract Quantity denoted below will participate in the following ISO-NE Markets (only check items that apply) once it has reached Commercial Operation or is otherwise designated as a qualifying resource by ISO-NE:

a. Forward Capacity Market: _________

b. Locational Forward Reserve Market: _____________

   i. If item d. above is checked, what Quantity (MW)?

   ii. Is Bidder expecting project to participate in both the summer and winter auctions? (Yes or No)

c. Day-Ahead Energy Market: ________

d. None: ________________

CAPACITY CONTRACT

The Annual Contract Prices in this Agreement be settled against (only one option can be marked as selected):

- Option 1: _______ the Market Price in the FCM only
- Option 2: _______ the Market Price in the FCM and the LFRM (the LFRM, in this case, represents the market clearing price net of FCM payments)
- Option 3:________ no market settlement possible (Option 3 must be selected if "d. None" was checked above. Note however that the terms of the ODR Contract may require modification of the Options selected and resulting settlement process for payment if and when ODR resources become eligible as capacity resources in the FCM.)

Please fill in the following table for appropriate years of the proposed Contract Term and Contract Prices depending on whether Option 1, 2, or 3 was selected. The Bidder may opt to settle against the LFRM (Option 2) for select years of the Contract Term. The Bidder may also choose to have different Contract Quantities for settlement purposes for LFRM and FCM under Option 2.

Depending on whether Option 1, 2, or 3 was selected above, different Annual Contract Price Columns should be completed:

a. If Option 1 or Option 3 was selected, Column B must be filled out.

b. If Option 2 was selected, both Column C (which indicates the price against with the FCM will be settled) and Column D (which indicates the price against which the LFRM will be settled) must be filled out.

Columns E (and E2), F, and G in the table below must be filled in for all years of the Term, starting with the Commercial Operation Date.

a. The Gross Contract Quantity reflects the nominal Capacity of the ODR Project.

b. The ODR Demand Reduction Value is the Capacity of the ODR Project as measured during ODR Performance Hours.

c. The ODR Capacity Value, which is equal to the Contract Quantity, is calculated by multiplying the ODR Demand Reduction Value by one plus the average avoided peak demand transmission and distribution losses, and (if and when applicable) the ICAP Reserve Margin. This is also expressed in the formula below:

Contract Quantity = ODR Capacity Value = ODR Demand Reduction Value x (1 + ISO-NE losses factor + ICAP Reserve Margin, if applicable)

***** THIS TABLE MUST BE COMPLETED TO**

PARTICIPATE IN THE PROCUREMENT PROCESS ***

A	B	C	D	E	E(2)	F	G
Contract Year	**Annual Contract Price ($/kW) for Option 1 and 3**	**Annual Contract Price ($/kW) for Option 2 (FCM settlement)**	**Annual Contract Price ($/kW) for Option 2 (LFRM settlement)**	**Gross Contract Quantity (MW)**	**Alternative Contract Quantity for LFRM (MW), at option of Bidder**	**ODR Demand Reduction Value (MW)**	**ODR Capacity Value [Contract Quantity (MW)]**

A	B	C	D	E	E(2)	F	G
Contract Year	**Annual Contract Price ($/kW) for Option 1 and 3**	**Annual Contract Price ($/kW) for Option 2 (FCM settlement)**	**Annual Contract Price ($/kW) for Option 2 (LFRM settlement)**	**Gross Contract Quantity (MW)**	**Alternative Contract Quantity for LFRM (MW), at option of Bidder**	**ODR Demand Reduction Value (MW)**	**ODR Capacity Value [Contract Quantity (MW)]**

**** AT BIDDER OPTION *****

CAPACITY CONTRACT CALL OPTION:

Is the Bidder electing the Call Option? (Yes or No): ____________[58]

Strike Price ($/MWh): ___________

Please supply an index against which Strike Price will be indexed (starting the day that winning projects are approved): *(Bidders may refer to publicly available indices, such as ISO-NE's fuel price index for the LFRM or the U.S. Consumer Price Index, or may provide at the time of the Financial Bid submission a customized index showing the year-on-year percentage change desired.)*

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58 The DPUC reserves the right to accept the Capacity Contract with or without the Call Option.

Call Option pricing: Please fill in table below (for all years of the Contract Term).

Contract Year	Call Option Contract Quantity (MW)[59]	Call Option - Supplemental Capacity Payment ($/kW)	Alternative Annual Contract Price ($/kW) for FCM under Option 2[60]

59 This cannot exceed the Contract Quantity specified earlier in Appendix J-2 for the Capacity Contract (i.e., the ODR Capacity Value).

60 Bidders can specify an alternative Annual Contract Price for the FCM if it chooses to bid for the Call Option, as the DPUC recognizes that contracting on the Call Option may change a Bidder's expectation regarding its expected energy profits within the Capacity Contract.

6.11 Appendix K: Model Protective Order

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

1. This Protective Order shall govern the use of all Protected Materials produced by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Order shall remain in effect until specifically modified or terminated by the Presiding Administrative Law Judge (“Presiding Judge”) or the Federal Energy Regulatory Commission (“Commission”).

2. This Protective Order applies to the following two categories of materials: (A) A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as protected those materials which contain critical energy infrastructure information, as defined in 18 CFR § 388.113(c)(1) (“Critical Energy Infrastructure Information”).

3. Definitions -- For purposes of this Order:

(a) The term “Participant” shall mean a Participant as defined in 18 CFR § 385.102(b).

(b) (1) The term “Protected Materials” means (A) materials (including depositions) provided by a Participant in response to discovery requests and designated by such Participant as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Order by the Presiding Judge, by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the

Protected Materials shall physically mark them on each page as “PROTECTED MATERIALS” or with words of similar import as long as the term “Protected Materials” is included in that designation to indicate that they are Protected Materials. If the Protected Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information -- Do Not Release".

(2) The term “Notes of Protected Materials” means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 5. Notes of Protected Materials are subject to the same restrictions provided in this order for Protected Materials except as specifically provided in this order.

(3) Protected Materials shall not include (A) any information or document contained in the files of the Commission, or any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order, or (C) any information or document labeled as "Non-Internet Public" by a Participant, in accordance with Paragraph 30 of FERC Order No. 630, FERC Stat. & Reg. **§** 31,140. Protected Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) Commission Trial Staff designated as such in this proceeding;

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding;

(5) a person designated as a Reviewing Representative by order of the Presiding Judge or the Commission; or

(6) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

4. Protected Materials shall be made available under the terms of this Protective Order only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Protected Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to

do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Trial Staff ("Staff"), Staff shall follow the notification procedures of 18 CFR § 388.112 before making public any Protected Materials.

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 9. Protected Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Protected Materials obtained through this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3 (d) above, the Participant shall seek agreement from the Participant providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate

shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this order.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing

Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to

Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 17, the Presiding Administrative Law Judge shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Presiding Administrative Law Judge, the parties to the dispute shall use their best efforts to resolve it. Any participant that contests the designation of materials as protected shall notify the party that provided the protected materials by specifying in writing the materials the designation of which is contested. This Protective Order shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said 5-day period, files a motion with the Presiding Administrative Law Judge, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the participant seeking protection. If the Presiding Administrative Law Judge finds that the materials at issue are not entitled to protection, the procedures of Paragraph 17 shall apply.

The procedures described above shall not apply to protected materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Protective

Order, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked “PROTECTED MATERIALS” and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list.

Such documents containing Critical Energy Infrastructure Information shall be additionally marked “Contains Critical Energy Infrastructure Information -- Do Not Release.” For anything filed under seal, redacted versions or, where an entire document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list and the Presiding Judge.

Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize or refer to any Protected Materials or information derived therefrom in testimony or exhibits during the hearing in these proceedings in such a manner that might require disclosure of such material to persons other than reviewing representatives, such participant shall first notify both counsel for the disclosing participant and the Presiding Judge of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

15. Nothing in this Protective Order shall preclude any Participant from requesting the Presiding Judge, the Commission, or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Order. The Presiding Judge may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

16. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Presiding Judge or the Commission.

17. All Protected Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Order. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release."

18. If the Presiding Judge finds at any time in the course of this proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Protective Order for three (3) business days from the date of issuance of the Presiding Judge's determination, and if the Participant seeking protection files an interlocutory appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 CFR § 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act. (5 U.S.C. § 552) for Protected Materials in the files of the Commission.

19. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Order.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

21. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

____

Presiding Administrative Law Judge

6.12 Appendix L: Code of Conduct

General

1.1 The evaluation of this RFP will be conducted in a manner to ensure that all bidders are treated in a fair and consistent manner.

1.2 The evaluation criteria and timing of the bidding process will be the same for all bidders. The DPUC (and its consultants) is the sole entity responsible for the evaluation and selection of winning projects.

1.3 The Connecticut distribution companies may bid in this procurement process if they so choose, and will be treated the same as other potential bidders.

1.4 The companies and any bidders registering to bid in this RFP must agree to adhere strictly to this Code of Conduct promulgated by the DPUC.

Information Disclosure, Process for Questions, and Communication Protocols

1.5 All information material to this RFP process will be distributed to all potential bidders.

1.6 In additional, all pertinent information will be posted on the RFP website at **www.connecticut2006rfp.com**, which will be open to all potential bidders and the public.

1.7 There will be a Pre-Bid Conference at which the DPUC and its consultants will answer bidder questions in a public forum. That Pre-Bid Conference is tentatively scheduled for the second week of October; the exact date, time, and location of the event will be posted on the RFP website by September 15, 2006.

1.8 In addition, the DPUC and its consultants will respond to questions throughout the RFP process. Bidders should submit all inquiries or requests for additional information in writing to:

RFP Coordinator
London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
Email: RFPCoordinator@Connecticut2006RFP.com
Phone: 617-933-7225
Fax: 617-933-7201

1.9 All questions and comments submitted by bidders, as well as the DPUC's responses to such questions, will be posted on the RFP website. The official response to questions submitted by bidders is the written response posted on the RFP website. The DPUC's objective in posting these questions, comments, and responses is to ensure that all bidders are treated in a fair and equal fashion and have equal access to information that may be relevant to their proposals. The DPUC will not identify the name of the party submitting questions.

1.10 A log of all material communications will be maintained by the DPUC and its consultants, and will be part of the public record once the Final Decision has been issued approving the Contract(s).

Submission of information by potential bidders

1.11 Any bid information submitted to the DPUC should not be communicated by any bidder to any other potential bidder or the Connecticut distribution companies or other state agencies, other than the DPUC.

1.12 Only the DPUC (and its consultants, London Economics International LLC and Inland Energy Consulting, who are under Confidentiality Agreements) will have access to data submitted by bidders as part of their qualification package and financial bid.

1.13 Actual annual contract prices as submitted on the financial bid template by the bidders will be released publicly six months after the contract(s) have been approved by the DPUC.

Procurement Principles and Bid Evaluation

1.14 The Procurement Principles for this RFP were determined in Docket No. 05-07-20, *Development of a Process and Standards for Competitive Solicitation of Long-term Projects to Reduce Federally Mandated Congestion Costs*, issued on December 28, 2005 and are summarized below. For a list of all principles and standards, see Docket No. 05-07-20.

- As broad a group of potential bidders as is practicable must be notified and offered an opportunity to respond to the procurement process to maximize the number of responses.

- Procurement should be conducted in a manner to cost-effectively promote price consistency and stability and minimize revenue requirements over the long term while also balancing the need to further certain non-economic policy objectives.

- Non-discriminatory and timely access to relevant data and information shall be provided by the DPUC and the RFP Coordinator.

- The procurement process should maximize bidder flexibility to maximize the value each bidder offers, without undermining the Department's ability to meaningfully compare bid responses based on clear standards.

- The procurement process should produce contracts that minimize the risk or impact of non-performance by the winning bidders.

1.15 Only the DPUC (and its consultants, LEI and Inland Energy Consulting, who are under Confidentiality Agreements with the DPUC) will be evaluating the bids received in this RFP. The evaluation methodology is described in detail in the RFP.

Interaction of bidders and distribution companies (as counterparties)

1.16 The electricity distribution companies that will serve as counterparties to the contracts signed as a result of this procurement process will not be a part of the project selection committee and will not have access to any information on a preferential basis to other third parties until winning projects have been selected by the DPUC and its consultants.

1.17 The distribution companies, and specifically Reviewing Parties representing the distribution companies, will be obliged to sign a Confidentiality/Non-Disclosure Agreement before receiving the contracts for the winning projects, which will grant the contracts the status of "Protected Materials".

1.18 As per the Confidentiality/Non-Disclosure Agreement, the distribution companies will put in place appropriate "Chinese walls" to safeguard commercially sensitive information that the companies will have access to once they become counterparties to the contracts.

1.19 The distribution companies will treat as confidential the Protected Materials they receive as administrators of and counterparties to the contract. Protected Materials will not be used except as necessary for the administration of this contract, nor shall they be disclosed in any manner to any person except an official Reviewing Representative, who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out his or her responsibilities in this proceeding.