

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 05-07-14PH02 DPUC INVESTIGATION OF MEASURES TO
REDUCE FEDERALLY MANDATED CONGESTION
CHARGES (LONG TERM MEASURES)

September 13, 2006

By the following Commissioners:

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INTERIM DECISION

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I. INTRODUCTION

A. SUMMARY

In this Interim Decision, the Department of Public Utility Control approves the attached Request for Proposal (RFP) dated September 13, 2006. The RFP will be issued on September 15, 2006, pursuant to the General Statutes of Connecticut § 16-243 M, to procure incremental capacity to reduce Federally Mandated Congestion Charges. Specifically, the Department approves the Request for Proposal to procure long-term projects with the objective of reducing Federally Mandated Congestion Charges, and its associated appendices.

In developing this RFP, the Department has solicited the views of stakeholders in a number of open forum technical meetings; thus, the RFP and its associated appendices have been calibrated to meet the needs of as many of the views expressed by stakeholders during this process as possible. The RFP is a vehicle that encourages the participation of a broad range of different possible technologies, including generation, demand response, and energy efficiency, which should contribute to the competitive nature of bids in this procurement process. The Department has not pre-judged the results of this procurement process. Rather, the Department is committed to procure what it thinks is in the long term interests of Connecticut ratepayers. Finally, the Department's mandate through the Energy Independence Act was not to procure energy as part of this procurement process. However, as the RFP design has evolved and as the Department has listened to stakeholder concerns about rising energy prices, the Department has decided that it would be useful to attempt to mitigate the impact of energy costs for Connecticut ratepayers within this procurement process to the extent possible. The Department has developed a call option with a supplemental capacity payment to suppliers which will hedge energy prices, as is described later in this Decision and as is discussed more fully in the RFP. Although the inclusion of this call option will add some time to the Bid Evaluation process, and therefore prolong the timeframe from Financial Bid submission to winning bids announcement, the Department determined that this additional period of analysis (approximately six weeks) was worth the expected benefits of hedging energy prices for Connecticut ratepayers.

In October 2006, the Department will approve contracts, which include the contractual terms and conditions that successful bidders in this RFP will be required to adhere to. Winning bidders will be approved in a subsequent Decision in this proceeding in April 2007. Finally, no later than November 8, 2007, the executed contracts will be reviewed and approved with a Decision in a separate contested case proceeding.

II. BACKGROUND OF THE PROCEEDING

Pursuant to General Statutes of Connecticut § 16-243 M, also known as Public Act 05-01, An Act Concerning Energy Independence (EIA or the Act), the Department of Public Utility Control (the Department) opened the instant uncontested proceeding on its own motion. The purpose of this docket is to identify long-term measures to reduce Federally Mandated Congestion Charges (FMCCs) for Connecticut ratepayers.

A. INTRODUCTION TO CONCEPT OF FEDERALLY MANDATED CONGESTION CHARGES

General Statutes of Connecticut § 16-1(41) defines FMCCs as “any cost approved by the Federal Energy Regulatory Commission as part of New England Standard Market Design including, but not limited to, locational marginal pricing and reliability must run contracts.” The FMCC definition is broad and covers all of the charges imposed on Connecticut arising out of the Independent System Operator of New England’s (ISO-NE) administration of the wholesale power market that spans six New England states. ISO-NE currently operates a nodal energy market, where the market-clearing price for electricity (the Locational Marginal Price (LMP)) at any point of the network, represents the aggregate of the price of energy, congestion, and marginal transmission losses. Generally speaking, energy-based congestion costs and locationally-driven reliability supplements, such as costs associated with Reliability Must Run (RMR) agreements, are the result of the need to utilize higher cost local generation when transmission limitations and system operations preclude lower cost power from being imported from other zones or regions. The costs of other locationally-differentiated product markets currently being adopted by ISO-NE, like the locational Forward Capacity Market (FCM) and the Locational Forward Reserve Market (LFRM), will constitute significant components of FMCCs.

B. DESCRIPTION OF THE ENERGY INDEPENDENCE ACT (EIA)

The Connecticut legislature mandated that the Department issue an RFP for projects to reduce the impact of FMCCs on Connecticut ratepayers through the EIA. As defined in the Act, eligible capacity includes generation, demand response, and energy efficiency, thus this procurement process is similar to the Integrated Resource Planning processes undertaken under the previous era of electricity sector regulation.

Section 12 of the Act requires the Department to identify near-term and long-term measures that could reduce transmission congestion costs and orders the distribution companies to implement the steps the Department considers appropriate. The most important elements of Article 12 of the EIA are highlighted below.

Subsection 12(a) of the Act required the Department to identify near-term measures by November 1, 2005 that could be implemented by the electric distribution companies by January 1, 2006. This is referred to as Phase I of the FMCC reduction effort, which was addressed through Docket No. 05-07-14PH01. Subsection 12(c) of the Act further required the Department to develop and issue an RFP to solicit the development of long-term projects to reduce FMCCs, with the electric distribution

companies serving as the counterparty to any such contracts. It is this clause that is the subject of this current Interim Decision.

According to subsection 12(c) of the Act, the RFP must identify “measures that would reduce FMCCs for the period commencing on May 1, 2006, and ending on December 31, 2010” and may include but shall not be limited to “(1) customer-side distributed resources, (2) grid-side distributed resources, [and] (3) new generation facilities, including expanded or repowered generation”. 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 Department 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.

Finally, Section 12(i) of the EIA lays out the criteria by which the Department should judge the proposals. The Department can approve a contract if it determines that it will (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.

C. PARTICIPANTS

The Department designated the persons identified on the Service List, Attachment 2, as participants in the proceeding.

III. SUMMARY OF THE PROCESS AND KEY DELIVERABLES

With the objective of gathering the maximum amount of public input possible to ensure a successful procurement process, the Department has issued a number of work products for public review and comment. These include the assessment of investment needs in Connecticut, the draft RFP, and draft contract templates, as discussed in the subsections below.

The Department has released such work products with the express intention of gathering and integrating stakeholder input. In addition, the Department has also held public technical meetings on each major work product as a way to better understand the needs and viewpoints of stakeholders. Thus, all the documents being issued by the Department in this docket reflect considerable input from numerous stakeholders, representing a spectrum of differing viewpoints on a large variety of subject matters.

As discussed below, in some instances, the Department incorporated certain requested revisions into the RFP (and where appropriate, the Needs Assessment) and rejected others. The extent of the comments, written and oral, on the RFP preclude us from addressing each comment individually within this Decision. However, there is a substantial record on each and every point. Furthermore, a tabular summary of the major stakeholder comments (including the Written Exceptions filed on September 1,

2006), the Department's consideration thereof, and resolution is included as Attachment 3 to this Interim Decision.

A. NEEDS ASSESSMENT

As part of the process to solicit long term projects to reduce FMCCs, it was necessary to conduct a rigorous investment analysis focused on the needs of Connecticut, including the timing of incremental capacity needs, the type of capacity of needed, and where appropriate, location. While Docket No. 05-07-14 PH01 addressed Connecticut's short term needs, this Docket No. 05-07-14 PH02 has focused on the period from 2007 through 2021, consistent with the statutorily allowed maximum term of the contracts.

Following up on the Interim Report it submitted to the Department as part of Docket No. 05-07-14 PH01 in November 2005, the Connecticut Energy Advisory Board (CEAB) submitted to the Department its Report on Connecticut's Long Term Electric Capacity Requirements (CEAB Final Report) on April 7, 2006. The CEAB Final Report focused on the 2010 to 2015 timeframe and the objective of reducing FMCCs for Connecticut ratepayers, and was based largely on analysis of existing data from other Connecticut and ISO-NE sources. CEAB's main conclusions regarding investment needs were that Connecticut's most critical capacity needs were for peak resources and that the state must increase its operating reserve capacity in Southwest Connecticut by at least 350 MW by 2010 in order to meet the requirements of the ISO NE Markets.

The Department hosted Technical Meetings on the CEAB's Final Report on May 1, 2006, May 5, 2006, and May 9, 2006 to provide stakeholders an opportunity to discuss the Report's assumptions and conclusions. The Technical Meetings on May 1, 2006 and May 5, 2006 focused on the investment needs analysis, while the Technical Meeting on May 9, 2006 was opened to the larger issue of the procurement process mandated under the EIA. The written comments submitted by stakeholders and the feedback from the Technical Meetings provided useful input to the Department in moving forward in its assessment of investment needs and in designing the RFP process.

The Department released a detailed investment needs assessment, conducted by consulting firm London Economics International LLC (LEI or London Economics), on June 5, 2006, entitled Report on the Electricity Sector Needs of Connecticut, 2007-2021. The June 5, 2006 Needs Assessment approached the question of investment needs from a markets perspective, identifying the quantity of additional capacity needed to balance the supply and procurement targets in ISO-NE capacity market (FCM), the LFRM, and the Energy Market over a fifteen year period. These three markets were identified as the major contributors to FMCCs. In the June 5, 2006 Needs Assessment, a series of hypothetical scenarios were created. These scenarios were intentionally constructed in an abstractive manner and in a layered fashion (using the same demand forecast but varying levels of retirements and new entry above existing capacity). This approach was used in order to illustrate the mechanics of how capacity needs in Connecticut would change as a result of changing supply vis-à-vis demand.

The Needs Assessment began with a market by market review of investment needs, given a forecast of procurement targets for each market. A final stage of the analysis considered whether investments made for one product market could alleviate investment needs in another product market. The June 5, 2006 Needs Assessment concluded that local capacity needs for the LFRM will drive Connecticut's short-term needs, while the FCM will drive long term capacity needs in the state.

The Department invited stakeholders to submit written comments by June 12, 2006 and held a Technical Meeting on the Draft Investment Needs Report on June 15, 2006 to discuss the analysis and its underlying assumptions. In addition, a Technical Meeting via teleconference was held on June 27, 2006 in order to develop consensus on modeling issues related to estimating and projecting the procurement targets that ISO-NE would use in the future for the FCM. The bullets below summarize the major comments and critiques provided by stakeholders on the June 5, 2006 Needs Assessment. For a more extensive list of comments, see the transcript from the June 15, 2006 Technical Meeting and the written comments submitted.

Stakeholders had the following concerns with respect to the Needs Assessment issued on June 5, 2006:

1. There was a consensus among stakeholders that they would prefer that the scenarios in the Needs Assessment more closely aligned with the structure of the cases used for the Bid Evaluation in the RFP.
2. Stakeholders were concerned with some of the assumptions in the analysis, such as the use of "green light" capacity as short-term entry, the numerical age-based retirement rule, the estimated qualified supply from spinning resources to meet LFRM needs, and the demand forecasts. The analysis relied on ISO-NE's reference case (50/50) for demand. Although that is the approximation of the demand levels used to establish the Installed Capacity Requirement (ICR)¹ for the FCM, it is nonetheless lower than the 90/10 projections used by ISO-NE for reliability (transmission security risk) assessment.
3. Because of the accounting of demand-side resources, stakeholders also commented that the ICR projection was probably too high and therefore exaggerated incremental capacity needs in the long term. (The forecast methodology for ICR (and the Local Sourcing Requirement (LSR)²) was

¹ ICR is Installed Capacity Requirement. This is the amount of generating capacity (including qualified demand reduction resources) that is needed in New England in order to maintain the reliability of the electric system. ISO-NE performs studies each year to determine how much capacity will be needed the following year. That level of capacity is then purchased by Load Serving Entities each year. Under the FCM, the ISO-NE will determine the ICR on a more forward-looking basis so that it can procure capacity in the Forward Capacity Auction (FCA) to meet the projected ICR in the Commitment Period approximately three and a half years from the time of the FCA.

² LSR, or Local Sourcing Requirement, is similar to ICR. It is the amount of generating capacity (including qualified demand reduction resources) that is needed within a specific sub-region within

updated and received consensus support at the June 27, 2006 Technical Meeting.)

4. Stakeholders also expressed concern with the projected Locational Forward Reserve Requirement (LFRR)³ – the procurement target to be by ISO-NE for the LFRM. The ISO-NE was fine-tuning its methodology for establishing the LFRR and anticipated structural changes (in the form of transmission expansions) were expected to substantially impact the LFRR. Because ISO-NE's forecasts terminated with the 2010 procurement periods, there was some uncertainty about how the long term needs for the LFRM would evolve in the longer term.

On August 25, 2006, the Department released a final Report on the Electricity Sector Needs of Connecticut, 2007-2021 (August 25, 2006 Needs Assessment (revised), Attachment 4 to this Interim Decision).⁴ This version integrated a number of comments received from stakeholders and updated data inputs and revised assumptions. The model continues to use ISO-NE's reference case (50/50)⁵ demand forecast as the base assumption but also has a high and low demand forecast which is calculated using ISO-NE's high and low economic cases. The Department did not believe that using ISO-NE's 90/10 demand forecast was appropriate for a long-term assessment, given that it is highly unlikely that New England would actually experience

New England in order to maintain the reliability of the electric system in that sub-region. "Local" requirements are necessary because the electric transmission system in this sub-region is insufficient. Therefore, some level of "local" capacity is needed to safeguard against supply interruptions. The ISO-NE will use the LSR as the procurement target only if an area has been determined to be an import-constrained Capacity Zone, in which case, there will be a separate auction (FCA) for that area distinct from the FCA for the rest of New England.

- ³ LFRR is the Locational Forward Reserve Requirement. Reserves are needed in an electric system to provide "back up" in case there is an unexpected outage of a power plant, or the failure of some other key infrastructure, or higher than expected levels of demand. In these cases, reserve resources need to be able to start, synchronize with the transmission system, and provide energy within a short timeframe. The LFRR specifically dictates the amount of non-synchronized reserves that are needed in a specific sub-region of the transmission system. The locational requirement is needed because in some areas of the system, the transmission system is inadequate and cannot be relied upon to guarantee replacement or supplemental power any time that it may be needed.
- ⁴ Based on comments received in the Written Exceptions, the August 25, 2006 Needs Assessment has been revised to include the retirement of all of the emergency generation resources awarded contracts under the SWCT Gap RFP, once those contracts expire in May 2008.
- ⁵ The 50/50 demand forecast represents a projection that has a 50% chance of being exceeded, while the 90/10 demand forecast developed by ISO-NE has only a 10% chance of being exceeded. The 90/10 demand forecast therefore represents the load levels that would occur under extreme weather conditions, and is used for planning purposes related to worst case, contingency events. The purpose of this RFP process is to reduce cost to Connecticut load through the procurement of additional capacity. That purpose is best served by purchasing the amount of capacity that has the greatest impact on reducing costs to load. Purchasing resources that are rarely, if ever, needed is not the best economic choice for Connecticut ratepayers.

15 consecutive years of severe weather conditions such that 90/10 peak load conditions occur year after year. However, in order to take into account demand forecast uncertainty, two additional demand scenarios were incorporated into the analysis.

The modeling approach defining the scenarios was also refined to be consistent with the “baseline” outlook being developed for the Bid Evaluation. All of the scenarios now assume that there is no new entry (or retirements) before 2010, and that after 2010, generic new entry (proxy capacity) is added to the New England system when (and where) it is economic (subject to the underlying scenario definitions about accelerated or delayed entry dynamics).⁶ A project is economic when its expected profits from the ISO-NE Markets are sufficient to pay for its operating costs, including a commercially reasonable return on investment. Retirements are no longer determined using a fixed retirement age; rather, they are determined based on modeled economics. Existing units are assumed to be mothballed if they do not cover their going forward minimum fixed costs for three consecutive years.

The four scenarios used in the revised August 25, 2006 Needs Assessment include:

1. Scenario 1: a “Modified Market Outcome with Reference Demand Case” scenario, which starts with existing supply.⁷ Generic new entry (proxy capacity) starts entering the market in 2010 based on projected market dynamics. This scenario uses ISO’s reference (50/50) demand forecast;
2. Scenario 2: a “Delayed Entry with Reference Demand Case” scenario, which also starts with existing supply, as in Scenario 1. Generic new entry starts entering into 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;
3. Scenario 3: an “Accelerated Entry with Low Economic Growth Demand” 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 (based on an expectation following the ISO’s reference case demand forecast); however, demand levels turn out lower than expected, based on ISO’s low economic case demand forecast; and,

⁶ 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.

⁷ Existing supply includes supply resources in the 2006 CELT report, Project 100 capacity, SWCT Gap RFP, ISO-NE demand response program resources, and recently Department-approved conservation measures. After the SWCT Gap RFP contracts expire in May 2008, we assume that only 50% of the non-emergency generation resources remain on-line, given expected funding levels for such resources during the Transition Period and in the FCM. All emergency generation awarded a contract under SWCT Gap RFP is assumed to retire (this latter element is a modification of the original assumptions in the revised August 25, 2006 Needs Assessment).

4. Scenario 4: a “Delayed Entry with High Economic Growth Demand and Tighter Environmental Restrictions” scenario. Generic new entry starts supplementing existing supply beginning in 2014, reflecting a delayed market response due to uncertainty and siting delays. Market entry is based on ISO’s reference case demand projections, although actual demand proves to be higher (per the ISO’s high economic case demand forecast in this scenario). In addition, tighter environmental restrictions are incorporated, raising market costs in certain areas of New England and motivating additional retirements over time.

The new entry and retirement outcomes are the culmination of a dynamic modeling process that incorporates ISO-NE’s Energy Market, FCM, and LFRM, consistent with the approach that the Department will apply in the Economic Analysis of the benefits and costs of proposed projects for the Bid Evaluation.

Based on additional information from ISO-NE and stakeholders, assumptions about the various ISO-NE markets were refined from those used in the June 5, 2006 Needs Assessment. For example, the calculation of ICR and LSR for the FCM was adjusted to appropriately account for demand-side response as a qualified capacity resource. In addition, certain inputs into the ICR (and LSR) calculations were changed in order to more closely align the forecasts with those published by ISO-NE. The Department also adopted the use of the most conservative forecast for LFRR based on the range of requirements discussed by ISO-NE in its draft RSP 2006 and actual procurement for the winter 2006/07 auction. Although certain transmission improvements are expected to provide reserve benefits to Connecticut, the projected LFRR was held constant at conservative levels after 2010. Additionally, assumptions have been modified regarding the role of spinning units and baseload RMR units in the determination of qualified supply in the LFRM (the cutoff levels for participation of the former were reduced and baseload RMRs were eliminated from qualified LFRM supply based on current contract terms). In addition, the anticipated supply mix for the LFRM was modified to link with the forecasted market price in the Energy Market modeling (and therefore the Forward Reserve Heat Rate was dynamically determined in each year of the forecast rather than fixed at a constant level).

The analysis in the revised August 25, 2006 Needs Assessment concludes that Connecticut needs 629 MW of incremental new capacity in 2007, and specifically needs capacity that would qualify for the LFRM. The short-term investment needs across all four scenarios examined in the revised August 25, 2006 Needs Assessment are driven by the requirements of the LFRM. The variability across scenarios and years in the incremental capacity need 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 projected LFRRs. The short-term investment needs for Connecticut are higher than those presented in the Needs Assessment issued June 5, 2006 because of an increase in the LFRM procurement target for the Connecticut zone (reflecting ISO-NE’s actual LFRR in the August 2006 auction for the winter 2006/07 period) and a reduction in qualified LFRM supply from existing resources

(reflecting modifications to LEI's methodology for estimating qualifying LFRM supply made in response to comments from stakeholders). In the aggregate, the assumptions on qualified LFRM supply from existing resources in SWCT and Greater Connecticut in the revised August 25, 2006 Needs Assessment are consistent with the recently released results of the first LFRM auction (for the winter 2006/07 period).

Although the investment needs in early years are driven by LFRM requirements, the incremental capacity needs of the FCM dominate the investment needs for Connecticut in the longer term. 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). 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).

In contrast to the statewide needs, incremental capacity needs vis-à-vis the projected procurement targets in ISO-NE Markets in Southwest Connecticut are only driven by LFRM requirements. 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. 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. The ISO-NE continues to be concerned about 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. Substantial generation additions in other parts of Connecticut may not be accommodated as easily by existing transmission infrastructure and could create the need for incremental transmission investments.

The Needs Assessment sets the stage for the RFP that the Department will issue on September 15, 2006. It presents the range of incremental capacity that the state is projected to need, as well as the general type and location of such capacity needs, in order to ensure that Connecticut develops adequate supply to meet ISO-NE's expected procurement targets in the FCM, LFRM and the Energy Market. The Bid Evaluation process will combine the market price outcomes from the scenarios and assumptions in the Needs Assessment with the Financial Bids that are submitted to determine how much and what kind of projects to select. Although the Needs Assessment suggests that a certain quantity of LFRM-qualified resources are necessary to achieve the procurement targets set by ISO-NE, the Bid Evaluation approach the Department will follow for evaluating the projected costs and benefits of proposed projects (and Other Factors) may lead to procure a somewhat different set of resources.

B. RFP AND CONTRACT TEMPLATES

Between June 30, 2006 and July 25, 2006, the Department released drafts of the RFP and the three contract templates (one each for generation, demand response, and

conservation/energy efficiency) for public comment. Revised contract templates will be issued in September (taking into account the comments received from stakeholders up to this point in time) and the contracts will be finalized in October 2006 in a Second Interim Decision.

The primary objective of the RFP is to reduce the impact of FMCCs and other costs on Connecticut ratepayers by facilitating the development of new or incremental capacity sooner than might otherwise occur in the marketplace and by reducing or hedging the costs of FMCCs in the future for the benefit of ratepayers.

Thus, the RFP will procure new or incremental generation or demand-side capacity electrically located in Connecticut that will ultimately reduce costs to Connecticut load. The RFP process will entail a Pre-bid Conference to address bidder questions, a Qualifications Process to assess bidders' technical and financial credentials, and a Financial Bid stage, at the end of which, Bidders will submit binding project bids. Financial Bids are expected to be due at end of the fourth quarter of 2006. The Financial Bid will be denominated in terms of \$/kW/year, and will reflect the level of capacity payments the project needs in order to be developed and operated, taking into account expected profits from Energy Markets, Locational Forward Reserve Market, the Regulation Market, Renewable Energy Credits, and other potential income streams, where applicable. The RFP will also allow Bidders to offer to bid a one-way Call Option, which would provide the Supplier, if selected, a supplementary capacity payment. In exchange, the Buyer would receive a hedge on energy prices in the ISO-NE Day-Ahead Energy Market.

Only qualifying, conforming bids will be accepted in the Financial Bid, and only non-substantive changes to the contract will be accepted after the Pre-bid Conference. Note that the Department will carefully consider all suggested changes to the draft contract templates provided in writing and in oral communications until the Pre-Bid Conference. Thus these contracts will reflect considerable stakeholder input.

The Connecticut electric distribution companies, The Connecticut Light and 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 from the date of commercial operation of a project.⁸ There will be one counterparty per contract awarded, initially based on the physical location of project vis-à-vis the service territories of the distribution companies⁹. The costs for these contracts will be allocated equally on

⁸ The Connecticut electric distribution companies will be allowed to submit bids in this process, but any bid submitted must be a fixed price bid according to statute 16-243(c). The Department expects the electric distribution companies to submit bids that are consistent with their status as regulated entities. All bids, including those submitted by the electric distribution companies, will be evaluated on an objective and competitive basis. Should an electric distribution company bid be selected as a winning project, the electric distribution company will not be required to contract with itself. However, it will be bound by the exact same terms and conditions as laid out in the contract templates, which will be enforced in a regulatory manner by the Department.

⁹ The Department will re-allocate winning project contracts on an as-needed basis such that expected payment streams to the winning projects are balanced to result in an approximate breakdown of total

a unitary (load ratio) basis to all CL&P and UI ratepayers, resulting in a consistent \$/kWh charge, which will be part of the FMCCs on ratepayer's monthly bills.

Consistent with Section 12(i) of the Act, which describes the conditions that the Department must consider in approving the contracts, the evaluation of bids will be largely based on economic consideration of the project's anticipated impact on FMCC (energy, capacity, and forward reserve) costs to Connecticut load under a variety of different scenarios using a uniform discount rate of 9.8%, based on already approved rates of return for the two distribution companies. Additional factors, worth a total of 15% of the Final Bid Score, will also be assessed during the Bid Evaluation process. These additional factors include (i) reductions in major pollutant emissions, (ii) the use of existing sites and electric generation infrastructure, (iii) the benefits of fuel diversity, (iv) frontloading of costs vis-à-vis projected benefits, and (v) other project-specific benefits, such as (but not limited to) grid security improvements associated with the project, positive state economic impact through local taxes or unemployment reductions. In addition, each project will be evaluated for project execution risk. Only those projects that individually and in the aggregate (i.e., for the portfolio of winning projects) result in a positive net benefit (inclusive of the additional factors) to Connecticut ratepayers, and are not likely to result in market power concerns in ISO-NE Markets, will be selected.

Winning bidders and the electric distribution companies must sign the Department-approved contracts without any substantive modifications. The Department issued three draft contract templates - for generation, demand response, and other demand resources - between June 30, 2006 and July 27, 2006. This section gives a very brief description of the contracts, their common features, and how they differ. The contracts will be discussed in greater detail in a Second Interim Decision to be issued at the end of October 2006 once the contracts have been finalized after the Department considers stakeholder input received in Written Comments filed on August 3, 2006, and September 1, 2006, and comments from prospective contract counterparties during the RFP process until the Pre-Bid Conference. Additional written comments on the contracts from prospective contract counterparties (including potential Bidders and the electric distribution companies) will be accepted until 4 PM EST on October 6, 2006, and the Pre-Bid Conference, scheduled for October 10, 2006, will serve as the effective Technical Meeting on the contracts.

The contract structure to be used in this RFP will be a financial, one, which will hedge the cost of this new or incremental capacity for Connecticut ratepayers, and will require settlement against the ISO-NE Markets. In most cases, the contract will be settled against the FCM, or its successor market, and, at the election of the Bidder, against the LFRM. (The exception being the contract for conservation resources, as discussed below.) 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 bid in a specified way in those ISO-NE markets. Because of the long-term

payments of 20% from UI and 80% from CL&P. Remaining true-ups between the electric distribution companies will be determined in the semi-annual FMCC settlement proceedings.

nature of the contract, the contract will also have certain physical performance requirements of the projects over time.

For the contracts that settle against the ISO-NE markets, the contract 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 LFRM¹⁰ (at the option of the Bidder), will be used to settle the monthly payments between the contract counterparties. 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), with some adjustments, thus ensuring a stable stream of revenue to the supplier. 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, subject to certain adjustments.

The Capacity Contracts will also have a one-way Call Option to hedge energy prices for the term of the Contract. As discussed in the RFP, if the Bidder elects to submit a proposal with the capacity call option, he will be required to specify the supplemental capacity payment (\$/kW/year), the quantity of capacity covered by the call option (no greater than the Contract Quantity specified for the Financial Bid for settlement against the FCM), the strike price for the call option (denominated in \$/MWh), and an index for year-on-year changes to the strike price. If the Bidder's project is selected and the Call Option is chosen¹¹, the project will receive this supplemental capacity payment (above and beyond the settlement amounts discussed above). 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 the difference between the hourly ISO-NE Day-Ahead energy price and the specified Strike Price for each hour over the Term of the Contract when the ISO-NE Day Ahead energy price rises above the specified Strike Price. This Call Option is an effective cap on energy prices for Connecticut ratepayers for the Contract Quantity selected in the RFP with this option. Bidders will have the chance to comment on the design of the Call Option in written comments on the contract, which are due October 6, 2006.

For projects that do not settle against the ISO-NE Markets, which could include certain conservation and energy efficiency projects that are not eligible to participate in the FCM, there will be a different type of contract, which is referred to as the Other

¹⁰ The LFRM price referred to in the contract template is the "net" LFRM price, after reducing the FRA Auction Price for capacity payments (under the Transition Period and during the FCM, based on the FCA clearing prices). In their Financial Bids, Bidders' Annual Contract Prices for LFRM will reflect only the net LFRM price.

¹¹ The Department has the right to select a Bidder's capacity bid with or without the Call Option.

Demand Resource (ODR) Contract.¹² The ODR contract will entail an annual capacity payment in \$/kW terms conditional on project performance from the buyer to the supplier, similar to a traditional physical capacity agreement. If and when ODR resources become eligible to participate in the FCM and receive capacity payments through ISO-NE market mechanisms, the ODR contract will automatically convert to the two-way payment structure discussed above for the generation and demand response contracts.

The Department held Technical Meetings on the contract templates (and the RFP) on July 13, 2006 and July 14, 2006, and requested written comments from stakeholders to be provided by August 3, 2006. The Department will be releasing another draft of contract templates this month which potential contract counterparties will have until October 6, 2006 to submit written comments on. The Department expects to release final contract templates by the end of October, after which no substantive changes will be accepted, except as specified in the RFP and this decision. Contracts will be finalized with the assistance of input received during the stakeholder process conducted in this proceeding and comments received during the initial phases of the procurement process.

IV. DEPARTMENT ANALYSIS: THE RFP MEETS EIA GOALS AND REFLECTS STAKEHOLDER INPUT

A. STAKEHOLDER COMMENTS ON DRAFT RFP

During the July 13, 2006 and July 14, 2006 Technical Meetings, and in written comments filed with the Department on August 3, 2006 and filed Written Exceptions on September 1, 2006 and in Oral Arguments on September 8, 2006, stakeholders provided numerous insights and comments on the draft RFP. There were five major categories of stakeholder comments, as listed below. The list is not intended to be exhaustive, but constitutes the most important issues and comments submitted by stakeholders. Due to the voluminous record (many days of hearing transcript and many rounds of written comments) the Department does not address every single question or issue raised by every participant. Attachment 3 contains a tabular summary of the Department's resolution of issues raised by participants in both their August 3, 2006 and their September 1, 2006 written comments.

B. REVISIONS TO FINAL RFP BASED ON STAKEHOLDER INPUT

The Department carefully considered these comments by assessing each one in light of the priorities and guidelines listed in the EIA as well as the Department's objective of conducting an effective and fair RFP process that ultimately provides tangible benefits to Connecticut ratepayers. The final RFP (Attachment 1) contains revisions that reflect stakeholder input on key issues and that are consistent with the

¹² Note that technologies such as Demand Response which may qualify to participate in the FCM but at a derated level will not be granted an ODR Contract. Such projects should bid into this procurement process at the expected capacity level (taking into account the most updated information on ISO-NE performance requirements in the FCM which may require deratings).

requirements of the EIA. Below, the more prominent comments by stakeholders are discussed, including how and why the Department did or did not incorporate them into the finalized RFP.

1. Contract for Differences

Section 12(e) of the EIA requires that the contract under the EIA shall include the transfer to the electric distribution companies of all rights to the installed capacity, including, but not limited to, rights to locational forward reserve capacity. Some participants have questioned whether the financial contract for differences (CfD) contract for capacity complies with this provision.

Suppliers become obliged to provide new or incremental capacity, and are obligated to perform according to certain levels and in line with certain requirements as a result of the CfD. Although the distribution companies do not take title to any physical capacity rights, the CfD allows for the effective acquisition of capacity rights for the benefit of ratepayers. Moreover, NRG notes that capacity is not a physical delivered product under ISO-NE's FCM in their written comments.¹³ The Department believes that the CfD is consistent with the statutory obligations of the EIA and that it results in the acquisition of new or incremental capacity that would otherwise not have been obtained but for the contracts.

The CfD structure was preferred over a physical contract for a number of policy reasons. First, it allowed the Department to shield the electric distribution companies from taking on operating risks if they were to take title to the physical capacity rights and then re-sell or self supply into the FCM. In fact, UI notes in its written comments that the CfD structure is simpler to administer than a traditional physical purchase agreement.¹⁴ UI also notes that it eases some of their concerns regarding accounting issues.¹⁵ Section 12(i) of the EIA states that the distribution companies can retain or sell capacity rights acquired under the contracts as determined by the Department. The Department has determined that it is not in the best interest of ratepayers or the distribution companies to have the distribution companies engaged in the sale of capacity in the ISO-NE Markets because of the potential operating risks and potential adverse financial and accounting impacts.

The CfD structure and related contractual obligations on the Suppliers maximizes the impact of the incremental or new capacity solicited in this RFP. Suppliers are obligated to participate in ISO-NE Markets to the fullest extent possible and therefore are expected to make an impact on overall market prices. There will be a multiplier effect for the benefit of ratepayers as a result of the hedge created by these CfDs – even if the contracted capacity is a small portion of the supply meeting Connecticut's requirements, these contracted resources are expected to lower the market clearing

¹³ August 3, 2006 Written Comments of NRG, Exhibit A, Section 4.1(a).

¹⁴ August 3, 2006 Written Comments of UI, pgs.8-9.

¹⁵ Id.

price and therefore reduce costs to all load. The CfD is also expected to minimize accounting issues of concern to the electric distribution companies, as it does not, on balance, shift ownership risk from the Suppliers to the distribution companies.

Moreover, CfD contracts have successfully been used in the US and internationally in the electricity sector. The objectives behind the use of CfDs are diverse. CfDs are useful for hedging future market costs. They have also been utilized to incentivize new generation, and have also been successfully applied to mitigate market power. The RFP takes advantage of all these features of the CfD structure.

In summary, the Department believes that the CfD structure with settlement against the FCM and LFRM (the latter, only if selected by supplier) is the preferred approach in the context of the ISO-NE Markets and ISO-NE Market Rules.

2. Assessment of Energy Benefits in Bid Evaluation

Reduction of FMCCs is one of the primary criteria under the EIA for the Department to approve contracts awarded in this RFP. As noted in Section II.A above, the statutory definition of FMCCs includes all costs arising out of Standard Market Design. Therefore, assessment of the reduction in the total FMCCs to ratepayers associated with ISO-NE's application of Locational Marginal Prices (LMPs) in its Energy Market is sanctioned by the EIA.

Furthermore, although the EIA may prohibit physical contracts for energy rights, it does not forbid the Department from taking into account the potential benefits of new capacity on Energy Market costs. Section 12(i) of the EIA obliges that the Department approve contracts that provide for products and services at the lowest cost possible. Disregarding energy benefits in the Bid Evaluation would be counter to the intent of the EIA in this regard.

Under the Bid Evaluation process described in the RFP, the Department will consider the benefits of each project based on cost reductions to Connecticut load. The cost-benefit framework will also evaluate the costs of the contract for each project. Only those projects whose benefits (to Connecticut ratepayers) exceed their costs (after adjustment for Other Factors) will be candidates for contract awards. Therefore, this methodology ensures that a sufficient amount of expected total project benefits will go to Connecticut ratepayers from selected projects vis-à-vis the anticipated costs of the project.

3. Mitigation of Rising Energy Costs

Although the contracts envisaged in the RFP do not explicitly acquire energy rights, there are a number of mechanisms in the contracts that address mitigation of energy costs, including a Call Option, which will provide a supplemental capacity payment to Bidders while hedging the risk of high energy prices. The Contracts also have a number of bidding requirements, explicit and implicit, which protect against price spikes and prevent non-competitive bidding. Lastly, by virtue of its request for incremental or new capacity, this RFP will aim to expand the quantity and type of

resources bidding into the ISO-NE markets, which will further amplify the competitive market construct and ensure that Connecticut is not a separate pricing zone.

First, the Call Option on the Capacity Contract is intended to hedge energy costs for Connecticut ratepayers. The Call Option consists of the Buyer making a fixed monthly payment to the Supplier in exchange for the Supplier refunding to the Buyer the difference between hourly energy prices (in the ISO-NE Day Ahead market) and a Strike Price (specified by the Bidder in \$/MWh terms in Financial Bids) if and when hourly energy prices rise above the Strike Price in the ISO-NE Day Ahead Energy Market. The Call Option requirement on the Supplier will motivate it to bid into the Day-Ahead Energy Market in order to reduce its hedging costs (in addition, the FCM rules require that Suppliers participate in the Day-Ahead Energy Market). The Supplier will be motivated to bid such that energy prices do not exceed the Strike Price; otherwise, it has payment obligations to the Buyer. From the ratepayer perspective, the Call Option will effectively cap energy prices for the selected Call Option Contract Quantity. Thus, the Call Option serves as an important mitigation tool against high energy prices, for the benefit of Connecticut ratepayers.

Secondly, in addition to the safeguards imposed by the market rules (such as, but not limited to the refund by suppliers of Energy Market profits associated the Peaker Energy Rent (PER)), the contract explicitly requires that suppliers bid competitively in the Energy Market. In addition, there are onerous constraints on suppliers as a consequence of being found non-complaint with this competitive bidding requirement.

Furthermore, the RFP is poised to attract a diverse set of resources. To the extent that non-gas fired resources are procured, the resulting contracts will also partially hedge future gas price risk for the benefit of Connecticut ratepayers.

4. Eligibility Requirements of Resources to Participate in the RFP

In order to reflect the spirit of the EIA, the RFP was designed first and foremost to seek out new or incremental capacity. New or incremental capacity would be more effective at lowering market prices and therefore FMCCs than existing capacity. Since the Department is not expecting to contract capacity to meet the state's entire share of the capacity market requirement (e.g., Connecticut's peak load share of the system-wide ICR), the pursuit of new or incremental capacity is preferred, as it is more likely to lower the total costs to load.

The Department, however, is attempting to be as flexible as possible given this overarching intent. There are no restrictions on the size, location, or technology requirements for new capacity. The Department is following the essential qualifications highlighted in the EIA and soliciting bids from a variety of resources, including generation projects, demand response, conservation, energy efficiency, and distributed resources. The contracts accompanying the RFP have been tailored to accommodate as many types of resources as possible. The contracts can also adapt to changing quantities of capacity over the Term of the contract, therefore, facilitating the participation of demand response and other demand resources. The Department will be

relying on ISO-NE rules to determine how such projects will be compensated under this procurement process. For example, any Demand Response project that is eligible to participate in the FCM is required to bid its capacity (even if at derated levels) into this procurement process as a DR resource and settle payment according to the terms of the DR Contract. Other demand-side projects that do not currently qualify for FCM participation but are eligible for this procurement process should set up their bid using the ODR Contract, which provides for a standard fixed payment until market compensation is possible.

In addition, refurbishments of existing resources are qualified to participate in the RFP, as well as deactivated units. Indeed, in the Other Factors portion of the Bid Evaluation, projects that make use of existing sites with electric generation infrastructure or related transmission or fuel supply infrastructure are given preference over those projects that are not using an existing site and/or requiring substantial infrastructure build out. Furthermore, although an existing resource needs to expand its capacity rating to qualify for this RFP, it can apply to have a contract that covers its entire capacity (not just the incremental component) if such a contract results in sufficient positive net benefits for Connecticut ratepayers such that it is selected as a winning bidder.

The EIA provides numerous incentives for demand response (for example, through Phase I of the FMCCs reduction effort) and distributed resources (for example, through financing credits and other mechanisms addressed in the EIA). Nevertheless, the Department is willing to consider such resources within this procurement process as well. Fuel switching is not eligible to participate in the RFP as this type of resource does not qualify as Energy Efficiency per precedent standards set by the Department in other Dockets.

5. The Needs Assessment and Procurement Goals and Objectives

Some participants requested that the Department indicate how much capacity and what types of capacity resources will be procured through the RFP process. The RFP was designed to take advantage of the rigorous approach afforded by a cost-benefit framework. Moreover, the cost-benefit framework was necessary given that the solicitation was meant to seek out projects that would reduce overall FMCCs (and the costs of the contracts awarded through this RFP would effectively become future FMCCs). Therefore, it is not sensible to have the Department bind itself into procuring a set amount of new or incremental capacity or to have set asides for different types of capacity prior to reviewing the Financial Bid Submissions of proposed projects, since those Financial Bids will factor into the cost side of the cost-benefit equation.

One stakeholder recommended that we evaluate peaking and baseload plants separately. The objective of the Bid Evaluation methodology is to determine what type of technology (or what combination of technologies) results in the greatest net benefit to Connecticut ratepayers. The Bid Evaluation models do not favor one type of asset over another. In fact the Bid Evaluation models are set up to recognize the fact that different resources may serve the ISO-NE markets differently. Furthermore, project selection will

be conducted considering not only economic factors but also implications for reliability as well as other energy and environmental policy priorities enumerated in the EIA.

Note that the Needs Assessment and the Bid Evaluation are separate but linked analyses. The Needs Assessment lays out a range of required additional capacity, while the Bid Evaluation will be used to judge Financial Bids. However, the two are linked in that their underlying assumptions are internally consistent.

6. Timing of RFP Process

Several stakeholders requested that the RFP timetable be relaxed to allow for additional rounds of comments. Other stakeholders commented that the back-end of the RFP process was possibly too long (therefore pushing the construction start time out to the following year and possibly raising Financial Bids because of the timeframe necessary for Bidders to keep firm their bids). The timing of the RFP process is consistent with similar solicitations in other jurisdictions and reflects the time limit for seeking new capacity given the state's investment needs. The Department believes that the current RFP process schedule balances the concerns of all stakeholders.

Section 12(c) and 12(g), respectively, of the EIA required that the Department issue an RFP on or before February 1, 2006, and on or before May 1, 2006, evaluate and select proposal(s). The Department delayed implementation of the RFP as discussed in the March 2, 2006 letter to participants addressing the schedule going forward. The Department prudently delayed the implementation of the RFP in order to await the results of the FERC proceeding, in which the market structure for a new capacity market in New England was being designed. Now that the settlement has been filed and accepted by FERC in that proceeding, the Department has made every effort to move forward in a thoughtful and expedient manner to implement the EIA's requirements, consistent with the legislative intent to acquire capacity to reduce FMCCs. The schedule in the RFP has been constructed to accommodate the immediacy of the investment needs in the state as best as possible, taking into account that it takes anywhere from one to three years to install new capacity.

The process to date has allowed for extensive public participation, comment opportunities, and interaction between stakeholders and the Department. Additional comments on the RFP are unlikely to be necessary given the volume of feedback received to date. However, potential contract counterparties (including prospective bidders and the electric distribution companies) will have an opportunity to further comment on the contract templates until October 6, 2006 once the RFP process begins. The Department has attempted to design the RFP and contracts, as well as the overall process, to eliminate the need for contract negotiations after the selection of projects. In addition, the structure of the contracts (i.e., the general provisions of the CfD framework coupled with performance requirements that remain with the Supplier) are expected to minimize accounting issues that the distribution companies may have otherwise needed more time to process prior to contract execution.

7. Accounting and Financial Issues Raised by the Electric Distribution Companies

The Department believes that the distribution companies are not at financial risk, given that the statute provides for full recovery of contract prices paid to supplier, as well as the distribution companies' costs for administering the contracts. All these costs are fully recoverable through the FMCC charge on the customers' bills. The Department believes that the statutory pass-through structure of these contracts should, in principal, mitigate financial and accounting concerns for the distribution companies.¹⁶ The Department directs the distribution companies to inform credit rating agencies, accounting standards boards, and its auditors to fully consider the implications of the statutory pass-through mechanism, so that the distribution companies can prudently seek to avoid or mitigate unreasonable costs levied on ratepayers as a result of the mechanical application of generic accounting requirements and standards, without regard to the particular circumstances in this instant proceeding. The Department believes that unnecessary costs can be avoided if the credit rating agencies, accounting standards boards, and auditors understand the statutory cost-recovery mechanism designed for these contracts by legislature.

Moreover, the distribution companies receive a one-time, non-recurring award for facility improvements made in the distribution companies' transmission and distribution systems to support operation of the projects, per Section 12(p) of the EIA.

Although the Department believes that it is unlikely that the distribution companies are at risk for additional costs,¹⁷ the distribution companies will be entitled to recovery of prudently incurred costs. Consistent with the decision dated December 28, 2005 in Docket 05-07-18, Department Investigation of Financial Impacts of Long-term contracts on Electric Distribution Companies, if and when the distribution companies incur costs as a direct result of adverse impacts associated with credit rating downgrades or accounting treatments resulting from these contracts, the distribution companies can seek remuneration by initiating a Conn. Gen. Stat. § 16-19 rate proceeding at the Department. Additionally, until the contracts are finalized, the distribution companies have the opportunity to propose contract provisions designed to reduce any risk of adverse cost impacts they perceive could result from being a counterparty to contracts approved under the EIA.

8. Allocation of contracts to Electric Distribution Companies

In Written Exceptions filed with the Department on September 1, 2006, the electric distribution companies expressed a strong preference for each winning project to be assigned two contracts, one with each distribution company split on an 80%/20% basis (as per the peak load requirements of each distribution company). This

¹⁶ Note that the statutory passthrough nature of these contracts is also the rationale for the contracts' unilateral credit requirements.

¹⁷ UI, in its August 3, 2006 Written Comments, concedes that the CfD structure reduces the company's concern with respect to financial accounting standards.

recommendation was made due to the distribution companies' desire to avoid secondary contracts between one another, to match financial flow of funds on a timely basis, and their belief that this contract structure would further reduce potential accounting and finance implications for the contracts.

However, many potential bidders, including representatives from generators, demand response providers, and energy efficiency providers, responded that such contracts would be totally unworkable from a practical viewpoint. Problems cited included: concerns about default for the project as a whole under tri-party contracts, additional administration burden for the supplier and potential confusion over how each distribution company would assess contract conditions.

These arguments, in conjunction with Department concerns about administrative duplication and potential for conflicting interpretations of contract conditions, have convinced the Department that each project should only have one contract with a distribution company. Contracts for winning projects will initially be assigned based on the geographic location of that project vis-à-vis the service territory of the electric distribution company. However, to address the concern that one distribution company may have a disproportionate amount of contracts to administer as compared to its total load responsibility within the state, the Department has committed to ensuring that the contracts will be re-allocated if necessary in its decision on Bid Selection to ensure that the anticipated annual payments from the distribution companies are balanced approximately 20% for UI and 80% for CL&P, with final true-ups to occur during the semi-annual FMCCs settlement proceedings at the Department.

9. Other Criteria in the Bid Evaluation Process

The Final Project Score under the Bid Evaluation will weigh the Economic Analysis (which measures the net present value of the benefits and costs of projects) at 85% and the remaining 15% will be composed of the Other Factors. The original list of 'tie-breaker' factors has been expanded to consider stakeholder comments on the importance of benefits associated with environmental cost reductions, the negative social consequences of front-loaded costs, and the more general comment about the need to differentiate benefits across projects for each of these Other Factors (rather than to simply assign 0 points or 1 point).

It is important to note that some of the Other Factors (like the benefits of more efficient generation in reducing environmental costs, or the costs of environmental regulations compliance) are already incorporated into the Economic Analysis indirectly. Notwithstanding that fact, the following criteria will be assessed under Other Factors using a point system: (i) reduction in emissions of SO₂, NO_x, and CO₂ (using tons of avoided emissions per KW of Contract Quantity over Contract Term) (ii) use of existing sites and electric generation infrastructure, (iii) benefits of fuel diversity, (iv) front-loading of costs, and (v) other benefits (such as local economy impacts and grid reliability improvements). The RFP describes in great detail the mechanics of the point system and the varying levels of points that projects can earn based on their attributes in each of these categories.

Note, however, that the RFP intentionally does not describe the way that the Economic Analysis and the assessment of Other Factors will be combined to determine a Final Bid Score. To develop such a formula, it is necessary to know what the range of net NPVs of projects bids are in order to determine the effective dollar equivalent value of the Other Factor analysis. As the range of NPVs will not be known until Financial Bids are submitted, this formula can not be provided to stakeholders in advance. However, to address stakeholder concerns about this methodology, the Department will release a description of how the Economic Analysis and the assessment of Other Factors were combined when winning bids are announced.

10. Comparability of Proposed Projects

The RFP is anticipated to result in proposals from a diverse set of resources, with different time horizons for commercial operation and contract Terms. Depending on the characteristics of the resource and the Financial Bid, the net benefits associated with a particular proposal will differ from other proposals. In order to objectively assess proposed projects on an apples-to-apples basis, a single discount rate is applied to all proposals in order to evaluate the net present value of net benefits. The selected discount rate for the Economic Analysis has been chosen because it reflects the market risk that ratepayers are expected to take on. Discount rates developed for internal programs and other purposes are not relevant for the purposes of the Economic Analysis and this RFP.

However, the Department recognizes that different projects will have varying levels of risk in terms of project execution, commercial realization, and even in terms of ongoing project operation. Therefore, the Department intends to evaluate the project risk of each proposal. Ostensibly, conservation and energy efficiency projects face a lower project execution risk as compared to large scale new generation development. Therefore, it is unnecessary to apply a lower discount rate to such projects in the Economic Analysis, as recommended by a stakeholder.

11. Transparency of Bid Evaluation Process and Assumptions

The RFP lays out in great detail the process for Bid Evaluation and the modeling tools used in the Economic Analysis, as well as the scoring methodology for the Other Factors. The RFP contains as an attachment a model illustrating the calculation process of the costs and benefits and the scoring system for the Other Factors. Indeed, the level of information disclosure regarding the Bid Evaluation process, models, and assumptions is equal to or exceeds that in other comparable procurement processes. In addition, over the course of the RFP process itself, the Department and its consultants will make available publicly on the RFP website a variety of information supporting the Bid Evaluation process, including updates on the key modeling assumptions. The purpose of the dissemination of such information is to inform Bidders as well as other stakeholders so that everyone can clearly understand the Department's Bid Evaluation methodology and assumptions.

12. Oversight Role of Third-parties in the Bid Evaluation Process

This RFP process is different than the competitive solicitations that the distribution companies undertake as part of the Standard Service procurement process

in Docket 06-01-08PH01, Department Development and Review of Standard Service and Supplier of Last Resort Service – Phase 1. In contrast to the latter, this RFP process will be managed by a public agency, whereas the Standard Service procurement is conducted by the electric distribution companies. Therefore, there is no need for the same level of public agency oversight in this RFP, as it would be duplicative.

At the time the Department issues its decision selecting projects, the Department anticipates providing substantial information to the public explaining its selection process, including a description of the bids selected and a comparative analysis of those project proposals that were rejected (without allowing for identification of the bidders who were not selected). This package of information will also include the results of the market power analysis. Therefore, all participants will have an equal opportunity to evaluate the Department's decision regarding project selection.

13. Market Power Issues

The Department is committed to ensuring that this RFP results in a maximum pool of competitive project proposals. In addition, as part of the Bid Evaluation, the Department will also consider the impact of the new capacity contracted on market power in the ISO-NE Markets. The EIA specifies that the winning projects should (in part) be selected based on their ability to result in long term benefits for Connecticut ratepayers. Part of any such benefit is naturally to ensure that the wholesale electricity markets in New England remain vibrantly competitive.

Because of the nature of the contracts (which fix the compensation for Suppliers over the Term of the contract) and our express solicitation for new capacity (which will dilute the market power potential of existing resources), the contract awards will reduce, rather than increase, market power concerns in the FCM and LFRM. Although the profits for Suppliers from the Energy Market are not fixed, there are strong protections in the contract against non-competitive behavior, both in terms of bidding requirements and as a result of the PER refund. Nevertheless, the Department will carefully assess market power concerns in the ISO-NE Energy Market by conducting an HHI assessment of the market, and a strategic bidding analysis after relaxing our competitive bidding assumption. These two tests will provide the basis around which the Department can conclude whether any of the projects in the portfolio would result in the increased ability to exercise market power. The results of the market power analysis for winning bids will be released to the public at the same time that winning bidders are announced as part of the package of information describing and supporting the Department's determination of winning bidders.

The Department will also monitor the RFP process itself for non-competitive behaviors, assessing Bidder activity and Financial Bid levels. Indeed, the baseline scenarios developed as part of the Bid Evaluation process which will be used to determine net benefits are similar to the concept of a reservation price, providing the Department with another tool to judge the legitimacy and relative competitiveness of the Financial Bids vis-à-vis expected market trends.

C. RFP MEETS EIA GOALS

The RFP has been specifically created to meet the objectives of the EIA given the current market environment. At its most basic, the Department has interpreted the EIA to require an RFP that would seek projects that would help reduce costs to Connecticut load over time in the wake of rising prices and market rules changes that would otherwise further raise costs. The sections below enumerate how this RFP meets the goals and priorities of the EIA.

1. The RFP is an all-source procurement process, thus fulfilling Section 12 (c) of the EIA which states that the process may include but not be limited to customer side distributed generation, grid side distributed generation, and other new generation facilities. The objective of an all-source RFP is to obtain the best combination of projects and promote conservation and demand response to the extent that they are more cost-effective solutions than conventional generation. The RFP is intentionally not prescriptive in the type, size, or location of project or how that project should operate in ISO-NE Markets (however, the revised August 25, 2006 Needs Assessment issued by the Department does provide some guidance to bidders on such issues). The Department believes that the RFP design selected affords the most flexibility for bidders and should provide for the most innovative and competitive responses by bidders. The Department also believes it is important to allow bidders the opportunity to optimize their project and investments to the needs of the market and therefore the Bid Evaluation measures the potential benefits across the major ISO-NE wholesale power markets, as discussed further below.
2. The primary priority under the EIA is the reduction of FMCCs at the lowest cost to ratepayers. A competitive solicitation, such as this RFP, will produce the best (or lowest cost) projects available to ratepayers at the time, taking into account the products and services being acquired and other attributes of the resource. This RFP's evaluation criteria will analyze each project in terms of its ability to reduce costs to load with respect to the different components of FMCCs – capacity, forward reserves, and energy. In order to properly gauge the impact of the proposed projects on ratepayers, a “costs to load” standard will therefore be applied in the Bid Evaluation. Furthermore, the Department will not accept projects that are not expected to result in positive net benefits to Connecticut ratepayers, taking into account also Other Factors described in the EIA. As a result, any project that is selected in this RFP process is expected to result in the reduction of FMCCs and other benefits to Connecticut ratepayers from levels that would otherwise have occurred if the Department took no action, effectively satisfying the EIA's primary and secondary priorities.
3. The bid evaluation process analyzes projects based on both the primary and secondary priorities enumerated in the EIA. The Economic Analysis, which calculates the net present value of the project's expected costs and benefits, ultimately serves the long term interest of ratepayers and will

result in the greatest aggregate reduction of FMCCs as listed in Section 12(g). This process also will result in the lowest reasonable cost of such products and services and increased reliability (which is measured in economic terms in the modeling based on the value of lost load, i.e., the opportunity costs of supply interruptions), as dictated by Section 12(i) of the EIA. The Other Factors assessed in the Bid Evaluation process are also enumerated in the EIA, and therefore are consistent with the statutory obligations imposed on the Department.

V. DESCRIPTION OF NEXT STEPS

A. FINAL RFP

The procurement process is designed to encourage the development of long-term projects that will reduce the impact of FMCCs on Connecticut ratepayers. The Department will issue the final RFP as planned on September 15, 2006.

B. DEDICATED RFP WEBSITE

The Department will ensure that all bidders have access to the same information from the Department and that no bidder will have selective or otherwise preferential access to information from the Department through this RFP process, as is described in more detail in the Code of Conduct governing this procurement process, which is attached as an appendix to the RFP.

A website dedicated to the RFP process has been created and will be available to the public throughout the RFP process. The website address is: www.connecticut2006RFP.com. The RFP and contract templates, and all related documentation, will be available for download from the RFP website. All questions and comments submitted by bidders, as well as the Department's responses to such questions, will be posted on the RFP website. The Department'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 Department will not identify the name of the party submitting questions.

The Department has designated its consultant, London Economics, as the RFP Coordinator. All questions and requests about the RFP must be directed to the RFP Coordinator in writing via email at RFPCoordinator@Connecticut2006RFP.com. For urgent or purely administrative questions, the RFP Coordinator can also be contacted through the fax and/or phone number provided on the RFP website.

C. THE DEPARTMENT WILL APPROVE THE CONTRACT TEMPLATES IN A SECOND INTERIM DECISION

The Department plans to issue a Second Interim Decision giving final approval to the three contract templates after considering any comments received between now

and the Pre-Bid Conference, currently slotted for October 10, 2006. Written comments on the contract by potential contract counterparties must be submitted by October 6, 2006 at 5 PM EST, while the Pre-Bid Conference will serve, in part, as a Technical Meeting on the contracts. Once the contract templates have been approved by the Department, all bidders must be willing to accept the contract without any substantive modifications if they are selected as the winning bidder(s), and will be required to make representations to that effect in their Financial Bid.

D. FINANCIAL BIDS ARE DUE NO LATER THAN DECEMBER 13, 2006

Financial bids will be due on December 13, 2006, as documented in the RFP. The Department and its consultants will receive and review the bids, based on the bid evaluation methodology laid out in the RFP.

E. DECISION ON SELECTION OF WINNING PROJECTS

The Department will select winning bids and issue the Decision in April 2007 directing UI and CL&P to execute the contracts with winning bidders and file contracts for Department review and approval, within fifteen calendar days.

F. DECISION TO APPROVE CONTRACTS

After the Decision selecting winning bidders, the distribution companies will have fifteen calendar days to file executed final contracts in a contested case proceeding to be opened by the Department. The Department will conduct one contested case proceeding to review all of the contracts and will issue a Decision approving or rejecting each of the contracts. The scope of review in the contested case proceeding will be limited to assessing whether the projects selected meet the three criteria listed 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. The opportunity to raise any other substantive issues pertaining to the RFP and contracts is in this proceeding prior to the Department's final approval of the RFP (slated for September 13, 2006) and contract templates (slated for the end of October 2006).

VI. CONCLUSION AND ORDERS

A. CONCLUSION

The Department finds that the attached RFP is consistent with the goals of the EIA and the principles and standards approved by the Department in Docket No. 05-07-20, Development of Process and Standards for Competitive Solicitation of Long-Term Projects to Reduce Federally Mandated Congestion Charges. The Department approves the RFP. The RFP will be issued on September 15, 2006.

**DOCKET NO. 05-07-14PH02 DPUC INVESTIGATION OF MEASURES TO
REDUCE FEDERALLY MANDATED CONGESTION
CHARGES (LONG TERM MEASURES)**

This Decision is adopted by the following Commissioners:

Donald W. Downes

Anthony J. Palermino

Jack R. Goldberg

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Louise E. Rickard
Acting Executive Secretary
Department of Public Utility Control

Date

Table of Contents of Attachments to Interim Decision

Attachment 1: RFP and Bid Evaluation model

Attachment 2: Service List

Attachment 3: Tabular Summary of Department's Resolution of RFP-related Issues Raised by Participants

Attachment 4: August 25, 2006 Needs Assessment (revised)