

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL

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

November 16, 2006

By the following Commissioners:

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SECOND INTERIM DECISION

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I. INTRODUCTION AND SUMMARY

In this Second Interim Decision, the Department of Public Utility Control (Department) approves the attached Master Agreements for Generation and Demand Resources dated November 16, 2006 (Master Agreements). These Master Agreements will be used to facilitate the acquisition of long-term projects pursuant to the General Statutes of Connecticut (Conn. Gen. Stat.) § 16-243m to procure incremental capacity to reduce Federally Mandated Congestion Charges (FMCCs).

In developing these Master Agreements, the Department has solicited the views of stakeholders and potential bidders both in written format on several prior drafts of the Master Agreements as well as in numerous open forum technical meetings. As such, the Master Agreements reflect the needs and input of stakeholders, including potential Suppliers and the two electric distribution companies (who would serve as counterparties to the Suppliers). The views and comments of stakeholders incorporated into the Master Agreements have been balanced and calibrated to the best extent possible by the Department in the interest of creating contracts that are consistent with contracts entered into by willing buyers and sellers in other jurisdictions, fair to all parties, and conducive to stable and long-lived commercial arrangements. The Master Agreements also reflect the Department's commitment to an all-source procurement process, treating each resource (and Supplier) on an equivalent basis as possible within the contractual framework, subject to specific technical and financial characteristics.

Finally, the Department has worked to balance the needs of key stakeholders in this contract: the Connecticut ratepayers, who will ultimately be paying for the cost of the contracts; the Connecticut electric distribution companies, who will be administering the contracts and should not incur excessive financial burdens for this responsibility; and the Supplier(s) (i.e., the ultimate winners of the on-going RFP process), who need to be able to secure financing to develop their project(s) and have a financially viable business model in order to operate their project(s). Some stakeholders have criticized the fact that the Department has made certain changes to the Master Agreements requested by potential bidders, which shift some risk from the Supplier to ratepayers. These changes were made because the Department continues to believe that the greatest risk to ratepayers is in not procuring sufficient (or any) capacity, which would ultimately result in higher costs to ratepayers. As such, the Department believes that it is imperative to design a Master Agreement that will attract investment and provide a commercially reasonable and sustainable framework for the continued operation of contracted resources over the full term of these arrangements, which will ultimately benefit ratepayers.

The Master Agreements approved with this Second Interim Decision include the contractual terms and conditions that the electric distribution companies (as the Buyers) and successful bidders in the ongoing RFP process (as the Suppliers) will be required to adhere to. Winning project bids will be approved in a subsequent Decision in this proceeding no later than April 2007. Finally, no later than November 8, 2007, the Department will review and approve the executed contracts with a Decision in a separate contested case proceeding.

II. BACKGROUND OF THE PROCEEDING

Pursuant to Conn. Gen. Stat. § 16-243m, also known as Public Act 05-01, An Act Concerning Energy Independence (EIA or the Act), the Department opened the instant uncontested proceeding on its own motion. The purpose of this docket is to implement a competitive procurement process to solicit new resources in order to reduce FMCCs for Connecticut ratepayers over the long term. On September 13, 2006, the Department issued the First Interim Decision approving the RFP for incremental or new capacity.

A. INTRODUCTION TO CONCEPT OF FEDERALLY MANDATED CONGESTION CHARGES

Conn. Gen. Stat. § 16-1(41) defines FMCCs as “any cost approved by the Federal Energy Regulatory Commission (FERC) 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 (Locational Marginal Price or 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 also constitute significant components of FMCCs.

B. DESCRIPTION OF THE ENERGY INDEPENDENCE ACT (EIA)

The Connecticut legislature mandated that the Department issue an RFP to procure new or incremental capacity 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 electric 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 resulting contracts. The First Interim Decision, issued on September 13, 2006, approved the RFP for this procurement process, while this Second Interim Decision approves the Master Agreements that govern the obligations of contract parties.

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 project proposals and approve contracts. 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 1, as participants in the proceeding.

III. SUMMARY OF THE PROCESS AND KEY DELIVERABLES

A. PROCESS SINCE LAST INTERIM DECISION (SEPTEMBER 13, 2006)

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, preliminary drafts and the final RFP, and several drafts of the Master Agreements, as discussed 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. There have been five technical meetings where the draft Master Agreements were discussed, the most recent of which occurred at the Oral Arguments on November 9, 2006.

As discussed below, the Department incorporated certain requested revisions into the Master Agreements and rejected others. The extent of the comments, written and oral, on the Master Agreements preclude us from addressing each comment individually within this Decision. However, there is a substantial record on each and every point.

B. MASTER AGREEMENTS

The Master Agreements attached to this Second Interim Decision represent the fourth public iteration of these documents, each integrating additional stakeholder comment, internal Department reflection, and ongoing ISO-NE market developments.

The contract structure to be used in this procurement process will be a financial one, which will hedge the cost of 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 and/or the Day-Ahead Energy Market. The Supplier will be required to participate in the ISO-NE Markets for which it qualifies (both technically and economically) in order to receive payment. Because of the long-term nature of the contract, the contract will also have certain physical performance requirements of the projects over time. There are two Master Agreements – one for generation projects and another for demand resource projects.¹

For the contracts that settle against the ISO-NE Markets, the contract will have a variable payment structure incorporating the FCM and LFRM payments already in place. Bidders will submit a Financial Bid in \$/kW per annum terms,

¹ Note that this differs from the initial drafts of the Master Agreements where the Department had proposed three Master Agreements – one for generation, one for demand response, and one for other demand resources. ISO-NE has refined its proposed approach to integrate demand resources into the FCM, now aggregating all demand resources into one large category. Given that the Master Agreements settle against the FCM, the Department has decided to mirror ISO-NE's classification and to use one Master Agreement for all demand resources.

referred to as the Annual Contract Price. This price, along with market clearing prices in the FCM and the LFRM² (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 Master Agreements also include an optional one-way Call Option to hedge energy prices for the Term of the Agreement. As outlined in the RFP, if the Bidder elects to submit a proposal with the Call Option on energy market prices, 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 chosen³, the Supplier will receive this supplemental capacity payment. In exchange for this fixed, guaranteed additional revenue stream, the Supplier will pay to Connecticut ratepayers (through the Buyer) the product of its Call Option Contract Quantity and the difference between the hourly ISO-NE Day-Ahead Energy price at the Connecticut Load Zone 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 Call Option Contract Quantity selected in the RFP.

The Master Agreements for generation and for demand resources are very similar, and both use the market settlement process. In recognition of the basic different characteristics of generation and demand resource technologies and their treatment by ISO-NE, there are certain contractual differences regarding the requirements for development and construction and some of the requirements for operation and contract settlement. While the Master Agreements have been structured to settle against the FCM, the rules defining eligibility for demand resources in the FCM continue to be refined by ISO-NE and will not be officially submitted to FERC for approval until February 2007, with FERC approval coming some time after that. Hence, there remains some

² 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.

³ The Department has the right to select a Bidder's proposal with or without the Call Option.

uncertainty about how demand resources will participate in and be compensated by the FCM. The Master Agreement for Demand Resources thus contains certain provisions for demand resources that may be selected in the Bid Evaluation process but ultimately are not eligible in the FCM or not eligible at the capacity levels warranted in the bidder's proposal. After contract execution and if at any time during the Term of the Agreement, should ISO-NE change the currently drafted rules regarding demand resource eligibility such that certain winning projects are no longer eligible to directly participate in the FCM but are nevertheless expected to provide benefits to ratepayers, the Master Agreement will be restructured into a fixed capacity contract whereby the Buyer pays the Supplier to supply the Contract Quantity offered in the Supplier's proposal to the ISO-NE system at the Annual Contract Price listed in the proposal and documented in the Agreement. Should market rules changes by ISO-NE reduce the Supplier's capacity to a level below the FCM Contract Quantity, the contract will be amended to reflect this lower capacity but the Supplier will not be liable to the Buyer for liquidated damages for this reduction in the FCM Contract Quantity (as would otherwise be required).

The Department reserves the right to revise the Master Agreements should significant changes to the ISO-NE Market Rules for the FCM, which affect the viability of the Master Agreements or the anticipated economic balance between the Buyer and the Supplier, are issued before the winning bids are selected and the Master Agreements are executed. In that case, parties would have the chance to review and comment on any final proposed changes to the Master Agreements.

IV. DEPARTMENT ANALYSIS: THE MASTER AGREEMENTS MEET EIA GOALS AND REFLECT STAKEHOLDER INPUT

A. STAKEHOLDER COMMENTS ON MASTER AGREEMENTS

The Department has solicited extensive stakeholder comments on the various drafts of the Master Agreements. The Department issued four different drafts of the Master Agreements (the first on June 30, 2006/July 12, 2006, the second on September 22, 2006/September 29, 2006, the third on November 1, 2006 with the Draft Second Interim Decision, and the last with this final Second Interim Decision). Written comments from stakeholders have been accepted on each of these drafts as well as on several other occasions: written comments were accepted through August 3, 2006 on the first draft of the Master Agreements; Written Exceptions were accepted through September 1, 2006 on the first Draft Interim Decision and the RFP, though many of the comments also addressed the contracts; written comments were accepted through October 6, 2006 on the second draft of Master Agreements; following the Pre-Bid Conference, the Department allowed participants one additional week to submit more written comments in light of the discussions during the Pre-Bid Conference; and after the issuance of the Draft Second Interim Decision, comments were accepted through November 7, 2006. In addition to this voluminous written

record, the Department also held six full days of technical meetings on the contracts from the beginning of May 2006 through the the present month (May 9, 2006, July 13-14, 2006, September 8, 2006, October 10, 2006, and November 9, 2006).

Due to this extensive record, the Department does not address every single question or issue raised by every participant in this Second Interim Decision. Rather, in the subsections below, the Department provides an overview of the most salient points emerging from this feedback, highlighting the most important and prominent comments submitted by stakeholders.

B. REVISIONS TO FINAL MASTER AGREEMENTS 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 creating commercially reasonable, fair, sustainable, and long-lasting contracts that will provide tangible benefits to Connecticut ratepayers. The final Master Agreements (Attachment 2 and 3) contain revisions that reflect stakeholder input on key issues and that are consistent with the 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 Master Agreements issued with this Second Interim Decision. Note that these categories are listed in the order in which they appear in the Master Agreements. We have noted the items that are specific to one section of the Master Agreement by placing a reference to the specific section in parentheses behind the subtitle.

Attachment 4 to this Decision summarizes the Written Exceptions submitted by stakeholders in response to the Draft Second Interim Decision and draft Master Agreements issued on November 1, 2006. This Tabular Summary lists the main critiques, comments, and questions submitted by stakeholders in their November 7, 2006 Written Exceptions and the Oral Arguments on November 9, 2006. This Tabular Summary is organized by Master Agreement Article, and states if, how, and why the Department did or did not address each stakeholder comment in the Master Agreements.

1. Electric Distribution Companies as counterparties to the Master Agreement

In the First Interim Decision, issued on September 13, 2006, the Department stated that each project should only have one contract with a distribution company. This decision holds. However, based on questions from stakeholders, the Department has determined that contracts for winning projects will initially be assigned based on the electrical location of that project vis-à-vis the service territory of the electric distribution company (as opposed to the geographical location, as previously announced). As stated in the First Interim Decision, 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.

The electric distribution companies continue to argue for additions to the Master Agreements that will guarantee their cost recovery for these contracts. The Department does not think it is advisable to include such language in these Master Agreements, as the Master Agreement governs the terms and conditions in the arrangement between the Supplier and the electric distribution company serving as the Buyer. Cost recovery from ratepayers is not properly a contractual issue between the electric distribution companies and the Suppliers. The electric distribution companies' assurances of cost recovery are provided by the Act which provides for full recovery of contract prices paid to the Supplier by the Buyer as part of FMCCs, as well as the electric distribution companies' costs for administering the Master Agreements. The Department in this decision, and other decisions in this proceeding, has also indicated that the electric distribution companies will be paid all prudently incurred costs, including the contract price and their costs for administering the contracts. Moreover, the statutes governing the Department's regulation of the electric distribution companies' rates and constitutional law's prohibition against taking without just compensation are more than adequate to assure that the electric distribution companies will be entitled at all times during the term of these Master Agreements to recover all prudently incurred costs directly and specifically associated with performing their statutorily-mandated duty as counterparties to the Master Agreements. As such, it is unnecessary to include the additional provisions requested by the electric distribution companies in these Master Agreements.

The electric distribution companies continue to be concerned that the accounting treatment of some of these contracts on the electric distribution companies' books may increase their ongoing costs, despite the Department's use of the contract for differences structure.⁴ In the First Interim Decision, the Department said that recovery of costs associated with accounting issues related to being a counterparty to the contracts would be treated the same as potential negative financial credit rating impacts in the Department's decision dated December 28, 2005 in Docket 05-07-18, Department Investigation of Financial Impacts of Long-term contracts on Electric Distribution Companies.⁵ The Department went on to say that "if and when the distribution companies incur costs as a direct result of adverse impacts associated with . . . 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."

⁴ CL&P Written Exceptions dated November 7, 2006.

⁵ First Interim Decision, IV.B.7. p. 19.

2. Alternative Fuel Requirements for Gas-fired Generation (Section 2.6 (g))

The Department included a provision in the Master Agreement for Generation that all natural-gas fired generators must maintain a minimum amount of alternative (non-natural gas) fuel on-site that they can use to generate electricity with. The Department developed this requirement due to experiences during the 2004 cold snap when gas-fired generators were not able or willing to procure gas supplies to generate electricity.

Bidders have complained that this requirement is expensive and unnecessary as fuel can be transported if it is needed. Bidders were also concerned about permitting requirements for burning and storing such alternative fuel requirements.

The Department believes that the alternative fuel requirements for natural-gas fired generators are an important component of Connecticut's commitment to the reliability of the regional electricity network and will help to minimize the potential for supply interruptions should there be a natural gas shortage – for whatever reason. It is also important to note that the Connecticut Siting Council has required and is expected to continue to require new generation to have back-up non-natural gas fired fuel capability; therefore, the contractual obligation is also consistent with expected permitting and siting requirements that Suppliers will need to meet prior to achieving Commercial Operation. As such, the Department is maintaining this provision in the final Master Agreement for Generation. The Department expects that bidders will factor the cost of meeting this requirement into their Financial Bids. However, to address bidders' concerns about the overall burden of this requirement, the Department has made several adjustments to the requirement.

First, the amount of alternative fuel that bidders are required to keep on-site will vary depending on their actual operations profile. Generation facilities are required to keep enough alternative fuel to operate at the greater of (i) their annual average capacity factor for five consecutive calendar days (up to a maximum of 80 consecutive hours of operation at the summer demonstrated capacity) or (ii) 40 consecutive hours. (Any generation facilities that meet the classifications of the Master Agreement for Demand Resources, and therefore enter into that contract with the Buyer, will not be required to meet the alternative fuel requirements.)

Second, bidders will be required to warrant that they have the requisite environmental permits to burn the alternative fuel.

Third, if bidders can not meet the requirements of Section 2.6 (g) due to permitting restrictions or site size limitations, they will be required to submit such information as part of their Financial Bid, citing why they can not meet these requirements and attesting that their inability to do so is not due to any action or

inaction on their part. Suppliers will then be required to (1) store the maximum amount of fuel possible on-site; and (2) buy the remaining fuel to be stored off-site and set up a firm transportation contract for the remaining amount of fuel.

Finally, the Department has amended the structure of the liquidated damage for non-compliance with this provision such that the Supplier pays 1/30th of the required alternative fuel that is deficient for each calendar day it is deficient for 30 calendar days, at which point this will be considered a Supplier Event of Default.

3. Bidding requirements (Section 3.3)

A number of stakeholders protested the bidding requirements that the Master Agreements imposed on the Supplier in the FCM (and if relevant, in the LFRM). The bidding requirements in Section 3.3 of the Master Agreements were drafted to account for the fact that this RFP process is effectively compensating the winning projects for all their expected costs of operation; as such, the Department does not want projects to be setting prices and earning excess profits in these ISO-NE Markets. The Department was extremely careful that the requirements meet the letter of the law in the Settlement Agreement (which ISO-NE concedes in its written comments on page 1).

Nevertheless, ISO-NE and NEPGA claim that there are antitrust concerns with “price fixing” because of the bidding requirements on the Supplier imposed by Section 3.3(b) of the Master Agreements. It is self-evident that nothing in the RFP process could be construed to be collusion among power generators – the apparent antitrust concern that NEPGA posits. If generators were accused of collusion to fix prices or manipulate the FCA, it could not be attributable to the price band in Section 3.3(b) or any other terms of the RFP. *Cf. Fisher v. Berkeley*, 475 U.S. 260 (1986) (private actors not liable without private action). Thus, the power generators are not potentially liable for their private actions under the RFP process.

It is important to keep in mind that these are simply commercial, arms-length arrangements between two counterparties – a financial contract in which the state has determined the terms on which it will agree to approve rates that include electric capacity. There is no basis for challenging these purely vertical agreements between individual generators and electric distribution companies. Purely vertical agreements that set a price do not violate antitrust laws. See *United States v. Alcoa*, 148 F.2d 416 (2d Cir. 1945); see also *Verizon v. Law Offices of Curtis V. Trinko, LLP*, 540 U.S. 398 (2004).

Moreover, as a state-administered program, the RFP and the resulting Agreements are immune from antitrust claims because they are protected by the state action doctrine. The state action doctrine immunizes public and private participants in a regulatory program when the state is actively supervising such a program so long as the terms of the perceived ‘restraints on competition’ are

“clearly articulated and affirmatively expressed as state policy.” With regard to the first factor in establishing state action, Connecticut’s legislature has defined a well-articulated and affirmatively expressed policy for the RFP program – to reduce FMCCs. Section 3.3(b) is a key element of the overall Agreement to ensuring that FMCCs are indeed lower than they would have otherwise been. The second necessary component of state action – “extensive official oversight” by state officials – is met by the fact that the Department is actively involved in establishing the terms of the Master Agreements and the selection of winning projects in the RFP.

NEPGA also suggests that the bidding requirements in the Master Agreement’s Section 3.3(b) violate FPA § 222 and FERC rules. FPA § 222 makes it unlawful for entities “to use or employ . . . any manipulative or deceptive device or contrivance” in contravention of the Commission’s rules. Section 3.3(b) of the Master Agreement is in no respects an instrument of fraud or deceit. Moreover, the FERC-approved Settlement Agreement does not prohibit contractual provisions like the ones enumerated in the November 1, 2006 Master Agreements. Finally, the RFP is a completely public document, and the contract awarded under the RFP is an arms length transaction. There can be no argument that it was infused with fraud or deceit. For these reasons, FPA § 222 does not apply to these facts.

Despite the fact the Department does not believe that the critiques of ISO-NE or NEPGA are warranted, the Department has made some adjustments to Section 3.3(b) of the Master Agreement for Generation and Section 3.4(b) of the Master Agreement for Demand Resources. First, the Department has changed the requirement on bidding in the FCM to require all winning projects to bid as Existing Capacity, if possible, and therefore to effectively be price takers in the FCM. If the project is not eligible to bid as Existing Capacity, the Master Agreement directs the Supplier to bid in the Contract Quantity as New Capacity such that it does not set the Capacity Clearing Price in the FCM, consistent with the Department’s objectives that the Supplier not set the market clearing prices. Second, the Department has made a similar amendment to the bidding requirements in the LFRM, stating that the Supplier must not set the Auction Clearing Price in the LFRM and removing the specific numerical bidding requirements previously listed. The Department’s overarching objective in designing these bidding requirements is to explicitly prevent the Suppliers from setting high market prices and potentially gaming the market. The bidding requirements have been set consistent with the bidding behavior of a competitive, rational supplier who has entered into a contract which provides for a fixed remuneration, as intended by these Master Agreements.

4. Specifications regarding ISO-NE requirements

The Settlement Agreement submitted to, and approved by, FERC lays out the guiding principles for the development of the future FCM. We have relied on this document in drafting the Master Agreements to make them as consistent with the FCM as possible. We have included specific ISO-NE FCM rules, where

relevant and possible. In other cases, where the rules have not yet been finalized or where a consensus has not been reached in the drafting of the rules, we have relied on more general contract provisions that require the Supplier to obey all ISO-NE rules. By choosing this approach, the Department has made clear to Suppliers what their obligations will be, as ISO-NE refines its FCM rules and in case of any unforeseen eventuality going forward.

5. Liquidated damages

Liquidated damages are an important part of contracts and represent payments made by the Supplier to the Buyer in order to compensate for lack of or inadequate performance such that the Buyer does not receive the full benefits of the contractual bargain. Within the context of these Master Agreements, liquidated damages are effectively a way for Connecticut ratepayers to be compensated for capacity and associated performance characteristics that were promised in a Supplier's proposal and warranted under the Agreement, but were ultimately not delivered, requiring Connecticut ratepayers to incur replacement costs. As such, should the Supplier pay liquidated damages and/or an Early Termination Payment as a result of the Master Agreements, these payments would ultimately be credited back to Connecticut ratepayers.

There are two kinds of liquidated damages in the Master Agreements: one category focuses on the period leading up to Commercial Operation and the other category focuses on the operating period. The former class of liquidated damages is intended to ensure that the Contract Quantity is available for the benefit of ratepayers at the time and at the capacity level promised in the Supplier's Proposal, while the latter category focuses on the longer term performance of the resource and ensuring that ratepayers realize the expected benefits of the Contract Quantity as represented by the Supplier in his Proposal. Both of these categories are important for ensuring that Connecticut ratepayers receive the benefits they pay for and were promised. The winning contracts will be awarded based on analysis that uses as inputs the resource's Commercial Operation Date as well as its level of capacity (or demand reduction) and other technical parameters, such as its overall availability, heat rate and operating flexibility. If a project comes on-line late or at a smaller capacity level, ratepayers will forego benefits that they otherwise expected and conditioned the contract on. The replacement costs for such delays or reductions are a function of market conditions and the timeframe necessary to secure such replacement capacity (for example, it may take two to five years to bring online new demand side or generating resources). Likewise, the Master Agreements can have terms of up to 15 years, thus the performance of the asset must be maintained during this time such that Connecticut ratepayers realize their long-term stream of benefits from this project, in contrast to performance requirements in more short-term contracts, like the requirements that ISO-NE imposes on suppliers selected for a 12-month FCM contract.

Bidders have protested that the specific liquidated damage provisions are too high and that the cumulative impact of the liquidated damages will be onerous on them. They also claim that these liquidated damages are duplicative of penalties they will face in the FCM and (if relevant) in the LFRM. Finally, bidders have also argued that some of the liquidated damages are unnecessary as the Supplier already has sufficient motivation to optimize his performance.

The Department has listened to the critiques offered by bidders, has analyzed liquidated damage provisions from other similar contracts, and has made some adjustments to the liquidated damages provisions in the Master Agreements. For example, the Department has reduced some of the liquidated damage levels. The Department has also expanded the thresholds for paying liquidated damages so that the Supplier is much less likely to trigger the liquidated damage payment, and the Department has increased cure periods before liquidated damages are triggered, effectively making it less likely that Suppliers will incur liquidated damages for minimal levels of underperformance. For example, the Department has added a provision that grants the Supplier an additional six month cure period if it exceeds the 90 calendar day cure period for missing its Commercial Operation Date provided that the Supplier continues to pay liquidated damages and can demonstrate that it is making progress on achieving Commercial Operation. The Department has also amended the mechanism adjusting the Monthly Payment Amounts to account for ISO-NE penalties, in recognition of the complexity of these payment streams, and exclude other ISO-NE deductions that are not a result of poor performance (such as the Peak Energy Rents adjustments by ISO-NE). The revised Adjustment Ratio mechanism balances the loss of benefits to the Buyer against the potential for major financial hardship to the Supplier resulting from Supplier underperformance. Finally, the Department has also allowed for certain exceptions – for example, liquidated damages will not be incurred if the Supplier can demonstrate that a delay in its Commercial Operation Date is due to regulatory delay that the Supplier is not responsible for, the result of Force Majeure, or an appeal is filed regarding the selection of contracts in Docket No. 05-07-14PH02. In addition, the availability deficiency liquidated damage payment will be waived for those plants that are not expected to produce energy-related benefits for ratepayers, such as those plants bidding at least fifty percent or more of their FCM Contract Quantity into the LFRM based on their Proposal.

The current composition and level of liquidated damages are in line with other similar contracts used in recent years across North America, as is discussed below. They are not duplicative and will help to ensure that Connecticut ratepayers receive the expected benefits of the contracted capacity, upon which the projects were selected. The liquidated damages are limited to the effective replacement costs for products or services promised by the Supplier in its Proposal.

As an illustration of the reasonableness of these liquidated damages, we have listed the various liquidated damage provisions (including the Monthly

Payment Adjustment provision) in the table below, explaining their purpose and why they are not duplicative with other liquidated damages within the contract or with FCM penalties.

Description	Liquidated Damages	Rationale
Key Milestone Date missed by Supplier	<p>\$5/MW/calendar day (not applicable for demand resources)</p> <p>To be repaid with interest if the Supplier meets his stipulated Commercial Operation Date</p>	<p>This form of liquidated damages is a common way to protect the Buyer and help ensure that the Supplier keeps on track to meet his Commercial Operation Date. The Department has agreed to refund these liquidated damages in full (with interest) if the ultimate milestone of Commercial Operation is met in a timely fashion. Therefore, the Supplier’s risk exposure is moderated.</p>
Supplier misses Commercial Operation Date	<p>\$150/MW/calendar day for generation resources⁶</p> <p>(\$50/MW/calendar day for demand resources)*⁷</p>	<p>This form of liquidated damages is a common way to protect the Buyer and recoup the direct loss of contracted-for benefits. Indeed, this is likely to be less than the full replacement cost across the spectrum of benefits that a resource can provide (capacity, energy, forward reserves, and other claimed reliability and environmental benefits).</p>
At Commercial Operation Date, Seasonal Claimed Capability is less than FCM Contract Quantity promised in proposal	<p>\$450/kW for generation resources</p> <p>(\$200/kW for demand resources)</p>	<p>It is common industry practice to protect the Buyer and recoup the direct loss of contracted-for benefits. Typically, this figure is substantially higher and closer to the total investment cost of bringing a new resource online. The Department has conservatively reduced the burden on the Supplier in acknowledgement of the fact that over some time (two to three years for demand resources and three to five years for generation resources), other Suppliers may step into the market and fill the “shortfall” if market prices warrant such investment.</p>

⁶ If the delay in Commercial Operation exceeds the original 90 days and the resource is not able to participate in the FCM as intended, the above Liquidated Damage may be replaced by an amount equal to the replacement costs of capacity that has not been made commercially available, as is written in the Master Agreement For Generation Projects, Section 8.1(d)a.

⁷ Id.

Description	Liquidated Damages	Rationale
<p>After Commercial Operation Date, Summer Seasonal Claimed Capability is more than 3% less than the FCM Contract Quantity of the LFRM Contract Quantity</p>	<p>Positive difference (if any) between the Replacement Price for the foregone capacity and the amount that the Buyer would have paid under the contract; the contract quantity will be amended in the contract for subsequent payments.</p>	<p>This is a long-term contract, with a Term of up to 15 years. The Suppliers selected in the RFP have been judged on the basis of their multi-year benefit stream, including the quantity of capacity that they represented in their Proposal. Ratepayers are expecting that this level of capacity is provided into the market. Therefore, it is reasonable for the Supplier to pay the Buyer the replacement costs for the derated capacity over the term of the derating.</p>
<p>Actual average annual availability is more than 5% worse than the Target Availability for that Contract Year</p>	<p>Product of (i) the difference between average annual on-peak LMP at CT load zone and average annual off-peak LMP at CT load zone for the relevant Contract Year, (ii) the incremental value of the deficiency (i.e., after 5% buffer) calculated on a two year rolling basis, (iii) the FCM Contract Quantity, and (iv) the number of hours in the Contract Year.</p> <p>(applies to generation resources that are not primarily involved in the LFRM)</p>	<p>It is industry practice for the Buyer to require the Supplier to maintain the generator in top form during the entire term of long term contract, taking into account normal deterioration. The Supplier can schedule a specific Target Availability level for each year of the Term, and therefore reflect maintenance schedules and the normal decline over time in performance due to wear and tear,</p> <p>The Buyer is securing not only capacity market benefits but also energy benefits (where relevant) for ratepayers with the contracted capacity, therefore the Buyer needs to ensure that the Supplier delivers those benefits. The Availability performance requirements and resulting liquidated damage is meant to backstop this expectation.</p> <p>The price levels for determining the liquidated damages is intended to approximate the difference in LMPs resulting from the Facility not being available over a one-year timeframe. Furthermore, the Department notes that the use of the incremental MW deficiency (after accounting for the 5% buffer) reduces the financial burden of the liquidated damage amount on the Supplier. Finally, by analyzing availability on a rolling two-year basis, the Department acknowledges bidder concerns that maintenance requirements could shift a few months without any palpable impact on performance or benefit streams to ratepayers over the long term.</p>

Description	Liquidated Damages	Rationale
Monthly payments will be adjusted to account for penalties incurred by the Supplier in ISO-NE Markets	Payments under this contract will be withheld consistent with the Adjustment Ratio, after any ISO-NE PER adjustments have been added back.	This reduction is due to the fact that the contract requires the Supplier to perform in ISO-NE Markets as warranted. The Buyer should not pay for any performance that ISO-NE has determined is not worthy of payment. This is not duplicative of the capacity liquidated damages, as the Contract Quantity to be used in the Adjustment Ratio will have been amended to represent the lower derated quantity of capacity. Furthermore, this payment adjustment is not duplicative of the annual availability liquidated damage, which assesses the realization of energy benefits, rather than adequacy of capacity market participation.

The liquidated damage provisions listed above are consistent with other contracts used in North America. Most contracts include a liquidated damage provision for missing intermediate milestones and the Commercial Operation Date, and our estimates for those liquidated damages are equal to or less than liquidated damages seen in other contracts. For example, recent contracts issued by Great River Energy and Xcel Energy also use a liquidated damage of \$5/MW/calendar day for missing intermediate milestones.⁸ In Ontario, the liquidated damage for missing a milestone was much higher at Cdn.\$50/MW/calendar day.⁹ Likewise, liquidated damages for missing the Commercial Operation Date ranged from \$100/MW/calendar day (Xcel Energy during “off-peak months”) to \$300/MW/calendar day (Ontario for generation projects) to \$1,000/MW/calendar day (Great River Energy after 90 day cure period).¹⁰

There is also precedent for charging liquidated damages for availability below expectation. In a recent Xcel Energy contract, the threshold for triggering liquidated damages is set at 3% below target availability¹¹ and in a recent Puget

⁸To see examples of contracts from these companies, go to:

<http://www.greatriverenergy.com/files/035618.pdf>

and <http://www.xcelenergy.com/docs/corpcomm/PSCoAlamosaSolarRFP20060330-ModelPPA.pdf>

⁹Note that the current exchange rate is approximately Cdn\$1 = US\$0.89. To see OPA contracts, see <http://www.ontarioelectricityrfp.ca/Index.aspx?id=56>.

¹⁰To see examples of these contracts, see references in Footnote 8 and 9.

¹¹See Xcel Energy’s 2005 Dispatchable All-Resource Solicitation. No longer available on website, please contact Xcel Energy PR Department: <http://www.xcelenergy.com>

Sound Energy contract, the threshold trigger is even lower at 2%¹², as compared to the 5% the Department is using in the Master Agreements. The actual damages are calculated differently – with Puget Sound applying a liquidated damage equal to the percentage deficiency above and beyond the 2% buffer times the contract quantity times the contract price, and Xcel Energy simply reducing the contract price by 5% for the next two consecutive months if the Supplier falls below its availability threshold (97% of target availability) three times in a two month period.

Finally, most of the contracts we reviewed also contained provisions that required the Supplier to pay the replacement cost of any capacity and/or energy that was not supplied, consistent with the Department's approach in the Master Agreements. Recent contracts issued by Xcel Energy¹³ and South California Edison¹⁴ contain specific provisions dedicated to such adjustments, though they were not explicitly labeled liquidated damages.

Thus, considering the specific requirements of the Master Agreement vis-à-vis the products being offered by the Supplier in the ISO-NE Markets and the benefits derived by ratepayers from this supply, as well as the examples from contracts used for long term procurements across North America, the Department is convinced that the individual liquidated damages assigned in the Master Agreements are reasonable, in line with expected damages, and in line with contracts in other jurisdictions.

In addition, the Department has added a maximum cap on liquidated damages that the Supplier can incur after the project reaches Commercial Operation in order to limit Supplier overall exposure and facilitate financing. This post-Commercial Operation cap is \$300/kW for generation and \$150/kW for demand resources, and is intended to address stakeholder concerns about open-ended exposure to potential liquidated damages under the Master Agreements. There is already effectively a pre-Commercial Operation Date cap set at the amount which the Buyer must pay if he is unable to bring the proposed capacity on-line - \$450/kW for generation and \$200/kW for demand resources. Once the post-Commercial Operation liquidated damages cap is reached, the Buyer can immediately terminate the Master Agreement, pursuant to Section 8.7 of the Master Agreement, with the Supplier paying the requisite Early Termination Payment (if any), in addition to any outstanding liquidated damages.

¹²See Puget Sound Energy's 2005 All Source RFP at:
http://www.pse.com/energyEnvironment/rfpFiles/AS%20RFP_Exhibit%2009_PPA_Final.DOC

¹³ See Footnote 8 and 11 for examples of Xcel Energy contracts.

¹⁴ See <http://www.sce.com/EnergyProcurement/AllSourceRFO/> for examples of SCE contracts.

5. Adjusting Bids after Department Approval (Section 4.2)

Currently, the Master Agreements and the RFP allow for Financial Bids submitted on December 13, 2006 as part of the solicitation process to be updated if the Department has not approved the executed Master Agreements by November 8, 2007. All bidders who choose to continue with the procurement process will have their Financial Bid adjusted to account for changes in the underlying costs from December 13, 2006 through November 8, 2007, based on an electricity sector specific inflation index. Based on suggestions from a potential bidder, the Department has decided to use the Handy-Whitman Public Utility Construction Cost Index, which best reflects the cost increases that bidders building new facilities will incur. 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 bid selection process.

Bidders have argued that the firmness of the Financial Bids due on December 13, 2006 combined with the timeframe for contract approval (which may take up to 11 months from the date of Financial Bid submission) may oblige them to include a substantial uncertainty premium in their Financial Bids, as certain costs such as the EPC contract, are very volatile and could rise dramatically during an 11-month period. Bidders suggested allowing final Financial Bid prices to be renegotiated once the contracts were approved or to simply shorten the Bid Evaluation and contract approval period to a two-month window, from its current not-to-exceed length of 11 months.

The Department understands the concerns expressed by bidders and has extensively discussed the best way to address such concerns in light of other Department constraints, including the proposed timeframe, which can not be shortened, and the Department's mandate to procure the lowest cost portfolio on behalf of Connecticut ratepayers.

The Department can not shorten the not-to-exceed timeframe between the submission of Financial Bids and the date by which the Department commits to approve the contracts. The first part of the timeframe, which constitutes the Bid Evaluation process, is a complex one and will take at least several months to complete because simulation modeling will be competed with the exact details of each proposal in order to properly and thoroughly establish the costs and benefits to ratepayers. This is in line with other large-scale procurements. Indeed, for large procurement processes, like this one, it is common for the bid evaluation process to span about six months¹⁵, as opposed to the four months that is scheduled for this procurement process. The Department is also unable to shorten the second part of the timeframe, the not-to-exceed window for contract approval, as approval for these contracts will occur through a contested case

¹⁵ Based on a half dozen procurement processes that occurred in 2005, including Arizona Public Service (three months), Progress Energy Carolinas (four months), Xcel Energy (nine months), Puget Sound Energy (six months), and Long Island Public Authority (seven to eight months).

proceeding at the Department. While the Department will make every effort to facilitate a rapid approval of the executed Master Agreements, the Department must run a proceeding that allows all stakeholders to be heard and to carefully consider all issues raised by stakeholders. As such, the Department has prudently included a not-to-exceed window of six months for contract approval.

At the same time, based on its mandated through the EIA, the Department must select the lowest cost portfolio of projects. If the Department were to allow for Financial Bids to be renegotiated after the Master Agreements are executed or for winning projects to be allowed to update their Financial Bids according to an index subsequent to the selection of winning bids, the Department would not be certain that the final selected group of bidders were indeed the lowest cost of all bidders.

As such, the Department is maintaining its original stance in the RFP and Master Agreements about the true-up for Financial Bids. It recognizes that bidders may integrate a certain premium in their Financial Bids due to the time horizon between the submission of Financial Bids and the not-to-exceed date of contract approval. The Department will do its utmost to be as expeditious as possible in approving the executed Master Agreements.

6. Rationale and objectives of the Call Option (Section 6.5)

In the various technical meetings held to discuss the RFP and the contracts, several stakeholders stated that it would be useful for the Department to attempt to address the issue of rising energy prices within this procurement process. The Department agrees that rising energy prices are of concern for Connecticut ratepayers and designed the Call Option as a way to hedge future energy prices for Connecticut ratepayers, while providing for a supplemental capacity payment to Suppliers. The Call Option, which is described in Section III B above and set forth in more detail in Section 6.5 of the Master Agreements, enables Connecticut ratepayers to effectively purchase a fixed for variable swap on Day-Ahead Energy prices at the Connecticut Load Zone. As such, Connecticut ratepayers pay a fixed price for the number of contract years selected by the Supplier, and, in return, the Call Option effectively caps the energy prices they pay for the Call Option Contract Quantity at the Supplier's strike price. (Both the fixed price and the Strike Price will be detailed in the Proposal, and will factor into the Bid Evaluation of the Call Option.)

7. Default provisions (Section 8)

Many bidders expressed concerns about what they viewed as unequal default provisions in the Master Agreements. In many bilateral contracts, it is customary for the default provisions to be more similar for the two counterparties.

However, the Master Agreements were designed to accommodate a relatively unusual situation. The Buyer under the Master Agreement will always

be one of the regulated Connecticut electric distribution companies. Their role will be solely an administrative one, as the costs of the contract will be a direct pass-through to ratepayers. Cost recovery for the contracts is guaranteed by statute. There is no record evidence that either UI or CL&P is in danger of bankruptcy or whether they could ever go bankrupt given that both utilities receive regulated cost-of-service revenues. Indeed, the credit quality of the Buyer is not even a trigger for an Event of Default or a condition of performance of this Agreement. Furthermore, the Buyer does not have as active a role as the Supplier in this Agreement, and therefore does not need to have as many Event of Default provisions. In summary, the Buyer thus does not represent the same risks of default as the Supplier under this contract, which is reflected in the different default provisions of the Master Agreements.

8. Force Majeure (Section 9)

The original language of the Force Majeure clause contained several “carve outs” for which the parties to the Master Agreements could not claim Force Majeure, such as loss of fuel supply or an increase in costs. Bidders argued that some of the “carve outs” could themselves be caused by Force Majeure (for example, a terrorist attack on a major gas supply pipeline), and that such exceptions should be included.

The Department included “carve outs” for the case of loss of fuel supply and the breakdown of plant and/or equipment in the case that either eventuality was caused by Force Majeure itself. The Force Majeure provision still narrowly defines the cases for which parties can legitimately claim Force Majeure, as the Department does not want the Force Majeure to be used in anything but extraordinary circumstances.

In addition, the Department has lengthened the period of time that the Supplier will have in case an event of Force Majeure delays its Commercial Operation Date from a period of one year to 18 months. This addresses bidder concerns that Force Majeure events could delay the Commercial Operation Date by more than a year and that such delay should not automatically lead to termination of the contract.

9. Level and composition of Completion and Performance Security (Section 10)

The Completion and Performance Security, which must be submitted by the Supplier on the Effective Date of the Master Agreement (i.e., once the contracts have been approved by the Department), serves as collateral in case the Supplier does not complete the construction the facility up to the warranted terms and performance levels stipulated in his Proposal or is otherwise in violation of his obligations, such that there is a Supplier Event of Default and an Early Termination Event. The security would go towards defraying any outstanding liquidated damages and the Early Termination Payment. The

Completion and Performance Security differs if the Supplier has a generation project or a demand resource project and if the project is still being developed or if it has achieved Commercial Operation, consistent with the relative risks of construction and the potential payouts due to the Buyer from liquidated damages and Early Termination Payments. The Completion and Performance Security is required for the entire term of the Agreement.

Bidders stated that the level of the security requirement is too high and that it should be terminated once the project has reached commercial operation.

The Department has decreased the levels required for the Completion and performance Security (as well as the Project Security Deposit due with Financial Bids, which secures the Bidder's Proposal) from their original levels in order to reduce the financial burdens on the Supplier. The Department expects that this reduction will substantially reduce the costs that Bidders will include in their Financial Bids. The Department further notes that there is a sharp decrease in the level of security required once the project reaches Commercial Operation (from \$100/kW to \$25/kW for generation and from \$35/kW to \$15/kW for demand resources). The Department, however, does not agree that there should be no security requirements once the facility reaches Commercial Operation. There is still the possibility that the Supplier could default on its obligations after the project reaches Commercial Operation and therefore result in Early Termination Payments to the Buyer. The security serves as collateral for this potential situation.

The Department believes that the levels of the security required for these contracts are reasonable in light of this rationale, and in light of the fact that these security levels are consistent with security requirements in other procurement processes across North America. In the recent all-source RFP process in Ontario, Canada, security requirements for generation were Cdn.\$100/kW before the Commercial Operation Date, and Cdn\$25/kW after the Commercial Operation Date until the expiration of the contract, which is consistent with the security requirements in this Agreement.¹⁶ (Note that the current exchange rate is approximately Cdn\$1 = US\$0.89.) In the same RFP process, demand side resources paid a security of Cdn\$50/kW before achieving their Commercial Operation Date, and Cdn\$25/kW thereafter until the expiration of the contract, which is higher than the security requirements in this contract for demand resources. Xcel Energy requires a security of \$125/kW for all generation¹⁷, including renewables, for the entire term of the contract, a much higher security requirement than the Department requires once a generation facility achieves Commercial Operation.

¹⁶ To see OPA contracts, see <http://www.ontarioelectricityrfp.ca/Index.aspx?id=56>.

¹⁷ See Footnote 8 and 11 for examples of Xcel Energy contracts.

Finally, Suppliers are allowed to submit the Completion and Performance Security in the form of cash, a letter of credit, a performance bond, or any other form of surety instrument that is acceptable to the Buyer as long as it is not a corporate guarantee. The electric distribution companies are not in favor of accepting a performance bond, but in light of the fact that we are not allowing Suppliers to use guarantees, the Department would like to grant Suppliers some additional options. However, to address the electric distribution companies' concern about receiving requisite payments from the surety companies, the Department solicited, received, and has included language in the Master Agreements received from the electric distribution companies about the requirements on the sureties in case a performance bond is used by the Supplier as part of its Completion and Performance Security.

10. Transfer provisions (Section 12.1)

The Department's objective with the transfer provision is to ensure that the ongoing viability of these projects and the benefits that they are expected to provide to Connecticut ratepayers, are not endangered by the sale or transfer of the project to a company that is not capable of developing or operating the project as demonstrated in the original Proposal. Bidders were concerned that the language in the previous draft Master Agreements limited their ability to find effective financing (i.e., to sell minority stakes to passive investors), limited the activities of their affiliates, or otherwise unreasonably constrained them in selling the project to a reliable, capable party. Bidders were most adamantly opposed to the concept of a fixed period of time, during which the project could not be sold or transferred.

The Department understands the concerns voiced by stakeholders, and in light of its own objectives, has revised the transfer provision to allow direct or indirect change of control at any time, as long as the Supplier receives written consent from the Department, which shall not be unreasonably withheld (as detailed in the Master Agreements). The provision also allows for the sale or transfer of less than 50% of the membership interest or share capital without Department consent, so long as the Supplier continues to meet its overall obligations under the Agreement.

The Department has maintained the transfer provisions for the Buyer such that the Buyer can transfer this Agreement to a successor electric distribution company subject to the Department's approval. Several stakeholders argued that the Buyer's transfer should be restricted to only entities with a credit rating that is equivalent to or higher than the Buyer's credit rating. This restriction is unnecessary given the guaranteed cost recovery of the contract costs by the Act and the Department's role in approving rates and effectively ensuring the continued economic viability of the electric distribution companies in Connecticut. Moreover, this contract is a pass-through for the Buyer and, as such, the Buyer's credit rating is not required to support the administration of these contracts.

11. Market Rules Changes (Section 12.6)

The Department's overarching objective in general and in particular with regards to this procurement process is to protect ratepayers against unnecessary risk, especially given the deregulated nature of the wholesale power market. The terms of the market rules changes clause in the previous draft of the Master Agreements allocated all the risk of market changes to the Supplier.

Potential bidders strongly opposed this, stating that such contract provisions were unreasonable and were not likely to obtain financing. In light of these comments, the Department has attempted to restructure the market rules changes provisions to address the underlying concerns of bidders (not being stuck in an "out-of-the-money" contract due to changes beyond their control) as well as the Department's objective of protecting ratepayers and maintaining the original contractual bargain, which led to the selection of the project in the first place.

As such, the revised market rules provision now allows for either the Supplier or the Buyer to request renegotiation of the Agreement if it can prove that the market changes have resulted in a material adverse impact. For the Supplier, this material adverse impact is defined as an increase in costs that are not recoverable through then current or future revenues (not limited to the ISO-NE Markets under agreement) of more than 10%. The provision requires the Buyer and the Supplier to renegotiate the contract in good faith such that the economic balance of the agreement is restored to its original level at the Execution Date (date at which the contracts are signed).

Despite bidder requests, the Department has decided not to include a Change-in-Law provision in the Master Agreements. Such provisions are not universally used; indeed, many similar long-term capacity contracts do not contain any Change-in-Law provisions or contain provisions that explicitly require the Supplier to bear the risk of any Change-in-Law. The Department's overarching objective is to ensure that these Master Agreements will remain commercially viable for their entire term and to limit the number of times that they can be opened up for renegotiation for non-essential issues. Change-in-Law provisions are very broad, and in Written Exceptions and Oral Arguments, potential bidders were unable to provide concrete suggestions for appropriately defining the scope for the Change-in-Law provision. Moreover, such a broad provision does not seem as appropriate in the context of the contemplated contractual arrangements given that this a commercial arrangement involving business activities in a deregulated – rather than regulated – environment. The master Agreements are not full cost recovery contracts. Other unregulated sectors of the economy have many thriving businesses which have shown that they are able to sustain a business model over the long term in spite of the potential for changes in tax law or environmental requirements – they have shown the ability to shoulder such risks. We believe that the Parties to these Master Agreements can do the same. As such, the Department believes that it is

more appropriate to not include a Change-in-Law provision in these Master Agreements.

12. Confidentiality (Section 12.11)

The first drafts of the Master Agreements contained standard confidentiality provisions. Bidders voiced concern about the confidentiality provision because of the level of information the Supplier would be disclosing to the Buyer in the Exhibits to the Master Agreement and through the reporting requirements in the Master Agreement. The Buyer could, in the future, be a potential competitor to the Supplier. In response to these concerns, the Department added language to the confidentiality provisions explaining how the Supplier can seek confidential treatment for any of these disclosures. In addition, the Code of Conduct for the contract, which is attached to the Master Agreement as Exhibit E, requires the Buyer to put in place appropriate measures to ensure that the Buyer has adequate systems to protect the confidentiality of such contracts.

C. THE CONTRACTS MEETS EIA GOALS

The Master Agreements have 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 contracts that will deliver tangible benefits (through reduced FMCC costs from those levels that would have resulted without the contracted capacity) to ratepayers from a diverse set of possible resources. This, in turn, requires contracts that will allow each Supplier to secure financing and reach commercial operation and perform as warranted for a relatively long period of time. The sections below enumerate how these Master Agreements meet the goals and priorities of the EIA.

1. The Master Agreements are structured to treat all resources as equivalently as possible, making slight adjustments based on their technical characteristics and level of sophistication. In this context, the Master Agreements fulfill Section 12(c) of the EIA, which states that the procurement process may include but not be limited to customer side distributed generation, grid side distributed generation, and other new generation facilities.
2. The price settlement structure of the Master Agreements fulfills Section 12 (i) of the EIA, which requires the Department to approve contracts that reduce FMCCs while resulting in the lowest reasonable cost of such products and services. The Master Agreements settle against the ISO-NE Markets which contribute the largest amounts to FMCCs – the FCM, the LFRM, and the Day-Ahead Energy Market. Moreover, the Contract for Differences approach minimizes the likelihood of stranded costs for Connecticut ratepayers.

3. The Master Agreements also reflect the other priorities mentioned in the EIA. Performance provisions in the Master Agreements will enhance reliability, a priority mentioned in Section 12 (i), as does the requirement for natural-gas fired generators to maintain alternative fuel on site.

V. DESCRIPTION OF NEXT STEPS

A. APPEAL ON STANDARDIZED MASTER AGREEMENTS DUE WITHIN 45 CALENDAR DAYS

At this time, participants in this proceeding know that the Master Agreements approved by the Department are in the form of contracts for differences. The final terms and conditions are also now known. For reasons discussed in this and prior decisions, the Department believes that these Master Agreements are the best method for acquiring new capacity for Connecticut. In terms of the process going forward, participants in this proceeding now also know, as outlined below and described in prior decisions in this proceeding, that the Department (1) will not give the electric distribution companies 30 days to negotiate final terms of the contracts, as the contracts approved in this Second Interim Decision are final and only subject to further modification as provided for in this Decision; (2) will require the electric distribution companies to submit signed contracts with winning bidders within fifteen calendar days of the Department's issuance of its decision on selection of bids; (3) will take legal actions within its powers to ensure that signed contracts are submitted within 15 calendar days and will seek to penalize any electric distribution company pursuant to Conn. Gen. Stat. § 16-41 for any failure to comply; and (4) will limit the scope of the contested proceeding to the three issues enumerated in Section 12(i) of the Act.

At Oral Arguments, The Connecticut Light & Power Company (CL&P) and The United Illuminating Company (UI) expressed concern that some participant may seek to challenge the legality of the contract for differences under the Act. The Department is aware that the OCC and CL&P have raised this issue.¹⁸ The Department has determined that contracts for differences are not only permitted by the Act, but are actually preferable over physical contracts.¹⁹

In its Written Exceptions dated November 7, 2006 and at Oral Argument, CL&P expressed concerns about the scope of the contested case proceeding the Department will conduct to review contracts and about having to file signed contracts with selected bidders in fifteen calendar days.

The Department believes that now is the appropriate time, if any participant believes that it will be aggrieved by use of either the Master Agreements or by the Department's process going forward for selecting winning

¹⁸ Written Comments of the OCC dated August 3, 2006, pp. 2-6 and Written Comments of CL&P dated August 3, 2006, pp. 18-19.

¹⁹ First Interim Decision, IV.B.1., pp. 15-16.

bidders and approving contracts, to seek expedited legal review of the Department's decisions in this proceeding. As such, the Department orders that CL&P, UI, OCC or any other participant in this proceeding that intends to challenge the legality of the contracts or procurement process going forward to bring such claims within forty five days of the date of this decision.

This requirement is in the public interest as it serves several important purposes. First, it will reduce the uncertainty and associated risk surrounding whether or not the contracts or process will be challenged by making any such challenges known at this time versus later at the time of contract execution. If challenges are brought, interested persons, including the Department, can assess the likelihood of whether the participant will prevail or not with its challenge and guide their actions accordingly. Second, the Department, the electric distribution companies, bidders and other participants in the proceeding, will avoid wasting substantial expenditures of time, money and human resources proceeding according to the current plan if someone successfully challenges some aspect of either the Master Agreements or the procurement process after winning bidders have been selected. Third, if someone successfully challenges some aspect of the Master Agreements or the process at this time, it is possible that corrections can still be made so that the procurement can still move forward in a timely fashion. Whereas, if a successful challenge is made at the end of the process, the entire process would have to be done over again from the start. Finally, depending on the type of any legal challenge made, the General Assembly could choose to amend or revise the Act, if necessary, to enable the Department to proceed with timely implementation.

B. QUALIFICATION SUBMISSION DUE NO LATER THAN NOVEMBER 13, 2006

Forty-five potential bidders submitted more than 80 project registration forms by the deadline for project registration on September 29, 2006. More than 80 individuals registered and attended the Pre-Bid Conference on October 10, 2006. The next deadline for bidders was the November 13, 2006 deadline to submit qualification packages, including detailed project descriptions, a description of the bidder's technical and financial qualifications, and a preliminary description of anticipated project financing. The Department received more than 30 qualifications packages from about 20 different potential bidders.

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

Binding Financial Bids will be due on December 13, 2006. The Department and its consultants will receive and review the bids, based on the Bid Evaluation methodology laid out in the RFP issued September 13, 2006.

C. 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.

D. DECISION TO APPROVE CONTRACTS

The Department will conduct one contested case proceeding to review all of the selected projects and the executed 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.

VI. CONCLUSION AND ORDERS

A. CONCLUSION

The Department finds that the attached Master Agreements are 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 Master Agreements.

B. ORDER

1. Any participant that wishes to seek legal review of the Master Agreements and the procurement process going forward must seek legal review within 45 days of the date of this Decision.

**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

Date

Acting Executive Secretary

Department of Public Utility Control

Table of Contents of Attachments to Interim Decision

Attachment 1: Service List

Attachment 2: Master Agreement for Generation

Attachment 3: Master Agreement for Demand Resources

Attachment 4: Tabular Summary of Written Exceptions submitted on
November 7, 2006