

**STATE OF CONNECTICUT
DEPARTMENT OF PUBLIC UTILITY CONTROL**

**DPUC Investigation of Measures
To Reduce Federally Mandated
Congestion Charges**

**Docket No. 05-07-14PH02
October 18, 2006**

**Questions & Answers
Discussed at
Pre-Bid Conference held
October 10, 2006
In Hartford, CT**

1 Introduction

The questions listed below come verbatim from bidder emails as well as from the Pre-Bid Conference transcript. The DPUC answers listed below are the official response to these questions. This document, where it differs from the RFP and RFP Addendum, supersedes statements in those documents. The questions have been grouped according to themes for facility of reading, and questions that are similar have been grouped together with one comprehensive answer. There are four categories of questions: those related to eligibility, those on the RFP process, those on the contract, and those related to performance issues.

2 Eligibility Questions

2.1 Question

In several places in the RFP and in related documents there are references to the size of projects and that projects either under 5 MWs or over 5 MWs will fall into a certain category. It is not clear, however, what would be true for a project that was exactly 5 MWs. Could you please clarify?

In the Addendum [to the RFP] released yesterday [October 5, 2006], it is now stated that DG units are split into greater than or less than 5 MWs to follow the rules in the ISO-NE. However, the pending ISO-NE rules actually state that distributed generation shall not exceed 5 MWs or shall “not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater”. Should not the RFP be modified to reflect the full statement?

These questions pertain specifically to the classification of Distributed Generation (DG). The DPUC’s objective on this issue is to understand what quantity of DG capacity will ultimately result in expected benefits to ratepayers. If a distributed generation unit is interconnected with the grid, then the expected benefits to ratepayers are based on the size of the generation unit (even if the peak load of the industrial host is smaller), because the new generation resource can effectively offset demand elsewhere on the grid. If a distributed generation unit is not interconnected with the grid, then the expected benefits to ratepayers is the lesser of the size of the generation unit or the peak load of the industrial host being displaced.

Once the distributed generation project’s capacity quantity has been determined, the DPUC will apply ISO-NE guidelines regarding the distributed generation project’s classification for the purpose of contract selection, categorizing those distributed generation projects that are 5.0 MW and under or do not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected as Demand Resources and all others as generation. The different financial securities and performance obligations required of the Supplier and its project will be determined by the type of contract it signs.

To the extent that the size of the Distributed Generation project is larger than 5 MW or does exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, the DPUC would consider allowing the first 5 MW of the project be considered as a Demand Resource and the remaining portion be considered as a generation resource as long as those different capacities could be isolated for performance and accounting purposes, as the Demand Resource and generation Contracts have slightly different performance requirements. In this rare case, the project would have to sign two separate contracts with the Buyer for the Contract Quantity.

2.2 Question

If AN EMERGENCY GENERATOR project receives funding from the Connecticut Monetary Grants, can that project be included in this RFP after the 5-year Contract?

No. In addition, any projects that receive other ratepayer funding that covers 100% of a project's development costs, including but not limited to the Conservation and Load Management Fund, Project 100 (and the renewable project contracts), Clean Energy Fund and the various DG programs authorized through the EIA (such as DG capital grants, refinancing, waiver for distribution charges, etc.) will not be eligible for funding under this program for any capacity that was already funded. If funding previously covered only part of a facility's capacity, the unfunded capacity can qualify in this RFP. Generally, the DPUC never provides 100% of the development costs because the DPUC believes that developers need to have an invested interest in bringing the project to fruition.

If the Bidder has other ratepayer funding (which did/will not cover the full costs of project development), the Bidders need to describe the nature of such funding at the time of Financial Bid submission, providing as much detail as possible.

The bidder must also note if it expects to receive other ratepayer funding in the future (or expects to apply for any such funding in the future). The extent and probability of this funding will be considered in the Bid Evaluation, as discussed in the RFP. Once the Contracts are executed, if a project receives additional ratepayer funding, the DPUC has the right to make a commensurate reduction in the effective support that it is providing the project in the Contract in order to ensure that it is not doubly remunerating a project, as described in Section 3.5 (d) of the draft Master Agreements.

3 RFP Process

3.1 Question

Currently, no mechanism exists for notification to be given when facilities are de-listed. How will such delisting be tracked and/or accounted for in connection with calculating available capacity for Needs Assessment purposes?

As part of the RFP process, is the Department willing to require that de-listed facilities be publicly identified to the Department and potential competing bidders?

The Needs Assessment will not be “re-run,” as has been previously explained. This question is, however, relevant for the Bid Evaluation. The DPUC is tracking all accepted plant closures as they are announced by ISO-NE (for example, ISO-NE announced as part of the PAC meetings this summer that New Boston was being approved for retirement). Once such an announcement is made, the DPUC incorporates such retirements as permanent de-lists in its modeling.

In general, if the DPUC and the RFP Coordinator believe it is relevant and vital, the RFP Coordinator may post additional or updated information on the RFP website about the Economic Analysis for the Bid Evaluation process, for example, updated fuel prices, etc. However, the DPUC is not prepared to function as the repository of information about “de-listings,” as the approvals for such actions is granted by ISO-NE, not the DPUC. Therefore, the DPUC recommends that potential bidders follow the ISO-NE proceedings and public announcements with respect to new resource qualifications and “permanent de-lists” of resources that may be announced in the future as part of the ISO-NE Forward Capacity Market and collect information that way.

3.2 Question

Does the Commercial Operation Date have to be a date certain, or can it be tied to meeting certain criteria (i.e., a Commercial Operation Date on or before a specified date), and under what terms? If a date must be specified, can the Contract begin before the stated Commercial Operation Date if the plant comes on line early? (Recognizing the 15 year term limit, the Contract could terminate 15 years from the actual Commercial Operation Date.)

First, the Commercial Operation Date (COD) provided in the Financial Bid needs to be date-specific. It is important to note that the DPUC will be evaluating the expected costs and benefits of the project in the Bid Evaluation process using this expected COD. In addition, there are liquidated damages that are due if Commercial Operation is not attained before the stipulated COD in the Proposal and Contract, because delay in the commercial operation of contracted capacity will reduce ratepayer’s expected benefits (certain exemptions may apply as discussed in the Master Agreement for Generation).

The Term of this Contract begins after the official COD as represented in the Financial Bid. If bidders reach commercial operation before that date, they are free to participate in the ISO-NE Markets and receive all revenues from those markets. There is nothing in the Agreement that would bar a project from starting commercial operations earlier. However, payment under this Contract will not start until the official COD represented by Supplier in the Financial Bid and incorporated into the Master Agreement for Generation.

3.3 Question

If a Supplier can provide capacity online before November 2007, will the DPUC consider either retroactive payments or an expedited administrative approval proceeding?

No, the Contracts are all being approved at the same time, therefore there is no possibility of an expedited approval process for any one project. Retroactive payments will not be possible as Contracts will not yet have been approved.

3.4 Question

Since LFRM bidding is seasonal, will projects coming online anytime other than the first day of the applicable auction period be deemed to be "participating" in the relevant ISO-NE Markets during the interim period after the Commercial Operation Date but before the first applicable auction period? Will they receive any compensation pursuant to the Contract for this interim period?

Our guiding objective is that projects being paid under this Contract should be participating in the relevant ISO-NE Markets. Projects need to have bid in and been accepted into the relevant auctions (for example, the Forward Capacity Auction for the FCM and the Forward Reserve Auction for the LFRM) to qualify for payment. The deadlines for those markets are well-established. It is important for bidders to choose their milestone dates carefully, keeping in mind relevant ISO-NE deadlines.

3.5 Question

Will the DPUC issue a revised Generator Contract template following the October 10 Tech Session? If so, when?

Yes, the DPUC intends to issue a draft Interim Decision adopting the final Master Agreements for Generation and Demand Resources by the end of October 2006. As with any DPUC decision, a draft Decision will be issued and all interested parties will have an opportunity to submit written exceptions and present oral arguments. After that the Department may further revise the Master Agreements and the Commissioners will vote on a final Decision.

3.6 Question

Section 12 (i) of the Energy Independence Act provides for negotiation of a final Contract with the winning bidders: "i) An electric distribution company shall negotiate in good faith the final terms of the draft Contract, submitted under subsection (e) of this section and included in a proposal approved under subsection (g) of this section ... either party may request the assistance of the department to resolve any outstanding issues. No such Contract may become effective without approval of the department." The current Generator Contract template is very prescriptive. Consistent with Section 12(i), what changes will be permitted to be negotiated after the final Generator Contract template is issued?

Contract negotiations will be unnecessary given the process undertaken in refining the contract templates by the DPUC. The Master Agreements for Generation and Demand Resources that bidders will have prior to the Financial Bid deadline, in the Department's view, will be final Contracts, so there will be no necessity for any further negotiation after winning Bidders are announced as originally contemplated by Section 12(e). The rationale behind this is that the DPUC has determined that the best way to evaluate and compare the projects and to make a selection about winning bids is on an "apples-to-apples" basis, and that is best achieved by using a standardized Contract. The DPUC has made exhaustive efforts to arrive at these standardized Contracts. The DPUC has allowed substantial opportunity for stakeholders to offer their suggestions, to provide comment, and our intention is to essentially perfect the underlying template and to use that without significant modification.

3.7 Question

The utilities have raised various objections to executing RFP Contracts. If a utility refuses to sign a Contract with a winning bidder, what actions will the DPUC take to validate the Contracts?

Unless the electric distribution company gets a court order excusing it from executing a Contract, the Department's position will be that it will take any and all legal actions available to it to enforce the execution of the Contracts. That includes but is not limited to the Department's ability under Section 16-10 to take court action with the assistance of the Attorney General seeking enforcement of a DPUC Order. The Department also has the ability under Section 16-41 to open a proceeding and order civil penalties against any regulated entity that does not comply with the Department's Orders.

3.8 Question

Does the DPUC have the right to grant a Contract for only a portion of a bid (eg. 300 MW for a plant that bids 400 MW)? If so, is the bidder required to sign the Contract? If the bidder does not sign the Contract, will it lose all or a portion of its security deposit?

The DPUC will consider the Bidder's Proposal in its entirety and will not force any Bidder to sign a Contract for a portion of the Contract Quantity for settlement against the FCM, although the DPUC retains the right to accept or reject the Call Option that the Bidder may elect to include as part of the Proposal. Note that the DPUC will accept proposals that do not represent 100% of the project's summer seasonal claimed capability.

3.9 Question

To the extent that the RFP only Contracts for a portion of the plant's capacity, can the plant enter into any type of Contract with another party for its remaining capacity - during any season? (during the term of the Contract)

Yes, as long as it meets its obligations under this Contract and does not re-sell its commitment capacity under the Contract with the Buyer. However, there are a few provisions in the draft Master Agreements that refer to the entire Facility and not just the Contract Quantity (see Section 3.1 of the Master Agreement).

3.10 Question

Can bidders bid into the RFP contingent upon receiving permits and/or transmission rights? If so, how will the amount of the security deposit be calculated? Will the bidder lose its Project Security Deposit if it does not sign the Contract due to failure to receive permits and/or transmission rights?

Can bids be contingent on permitting that does not require material modification to the proposed facility?

Under Section 2.5 (b) of the Generation Contract are liquidated damages for not meeting the project's commercial operation date waived due to delays in obtaining regulatory approvals that are not the fault of the Supplier.

The Contract template gives relief from liquidated damages if government approvals are denied or appealed. What if the government approvals are denied or appealed? Are the damages payable? What if the ISO-NE interconnection application is delayed or denied? Are the liquidated damages assessed against the project as if a government approval was denied?

No, the Bidder takes the risk of receiving permits and transmission rights and will forfeit its Project Security Deposit if it is ultimately unable to get the project on-line, with the exception of Force Majeure conditions as described in Section 9 of the Master Agreements.

The draft Master Agreement for Generation and Demand Resources states that in the case of a delay that is not the Supplier's fault, the Supplier will not be liable for liquidated damages for missing a Key Milestone (as set forth in Section 2.5 (e) of the contracts). If the denial by a government agency is not due to the fault of the Supplier or a deficiency in the Supplier's filing, the Supplier will not have to pay liquidated damages. If the denial, including denial of an interconnection request, is because the Supplier was deficient in certain aspects of its filing (i.e., the project was not feasible under current rules or statutes) or was unwilling to follow through on certain requirements of approval (for example, funding of necessary transmission upgrades), then the liquidated damages would be payable by the Supplier.

On the question of appeal, an appeal should not result in delay unless there is a stay. Any delay due to appeal is likely to then be treated as an event of Force Majeure where no damages are due until resolution.

3.11 Question

Since 85 percent of the Bid Evaluation Phase is based on the NPV of the project costs, projects with earlier completion (i.e. commercial operation) dates will have a lower NPV and have a higher score, all other costs being equal. How will the risk of failure to meet the completion date be considered in the Bid Evaluation?

Generally speaking, the application of the NPV methodology and a discount rate will mean that projects that come on line earlier and can produce material benefits to ratepayers will have a higher NPV and therefore a higher score than those projects that come online later, holding all else equal.

The project execution risk is being assessed separately from the economic analysis. Those projects with a higher risk of being able to come on-line at the specified COD will be rated lower than projects with a more certain COD.

The information submitted as part of the qualification process, such as status and level of site control, status of each required permit, status of EPC contract, etc, will enable the DPUC to assess the project's execution risk. The DPUC will effectively use these items as a checklist to assess each project's execution risk. This is not, however, a type of analysis that can be conducted using a boilerplate template, given the vast differences in the project submissions the DPUC is expecting to see. The DPUC will, in the Decision on the bid selection, discuss how projects fared on the project execution risk assessment, comparing winning projects against projects that did not win. The Decision will also detail how large of a component project execution risk was in the overall selection decision.

3.12 Question

Under the Other Factors portion of the Bid Evaluation, will projects that have fuel oil as a backup fuel to natural gas be granted the 1.25 points as a “non-natural gas fired plants?”

No. For the purposes of assessing fuel diversity, any facility that is fueled primarily by natural gas or by oil will NOT be granted any points.

3.13 Question

In the Bid Evaluation, what assumptions will you use for the heat rates of projects given that the heat rate would differ as it is ramped up and down or dispatched at different load levels?

As part of the technical documentation submitted in the Qualification submission, the DPUC would expect bidders to provide as much detail as possible on issues related to heat rate. If bidders can provide the heat rate versus output curves, then the DPUC can incorporate that information in its Bid Evaluation.

3.14 Question

Can you clarify your evaluation of NPV and how you could calculate it for a five year project versus a 15 year project? Do I just NPV the cost side, or do I NPV the benefits as well?

The dollar costs for both the costs and the benefits over the relevant term of the proposed project's contract will be discounted back to 2006, so that the DPUC is looking at all projects on an equal footing, even if the Commercial Operation Date for one project is 2009 and for another project is 2012, and taking into account different possible contract lengths that bidders may propose.

3.15 Question

Will the track record of a large established brand name developer be favored more than a small independent developer who does not have the same track record?

In the project execution risk component of the Bid Evaluation, the technical and financial wherewithal of the project sponsor will be considered. The analysis will focus more on the funding directly available to the project and the experience of the individuals on the bidder's team than a trademark or a brand name. The RFP requests concrete evidence which demonstrates the bidder's experience, and which gives support to a bidder's claim that the project can be realized and operated commercially and reliably. In addition, other elements of project execution risk – level of site control and permitting – will also be considered.

3.16 Question

Within Southwest Connecticut, it would appear from ISO-NE figures that FMCCs as applied to existing generation assets vary greatly from city to city. Is it fair to assume that a generating facility in an area where the FMCCs are the highest will score higher than a project in an area with lower FMCCs?

The Bid Evaluation process is targeting the product markets that make up the majority components of FMCCs from a ratepayer's perspective. In that regard, energy market costs are based on zonal prices rather than nodal prices for load. Currently, there is a single zone in Connecticut for energy and therefore all ratepayers pay the same energy charge per MWh of consumption regardless of location. Similarly, LFRM costs are based on reserve zones, and it is currently anticipated that FCM costs will be the same across all of Connecticut. Therefore from a ratepayer's perspective there is no difference in major FMCCs by city. That being said, a bidder could argue that his specific project may offer special reliability benefits due to its location under the "other" category of the Other Factors.

3.17 Question

We understand that new generation built on existing sites will receive full brownfield credit. How many points will be credited to new generation built on an environmental brownfield site but not an existing generation site which has available all the existing transmission and gas pipeline infrastructure for the facility?

As the DPUC discusses in Section 5 of the RFP, if there is a site that has existing transmission and fuel supply infrastructure but is not in itself a pre-existing generation site, 2 points out of a total of 2.5 points will be granted to the project.

3.18 Question

What level of EPC commitment is required to submit a bid?

The Bidder is not required to have any specific level of EPC commitment in order to submit a bid, however, proof of some level of EPC commitment is likely to reduce the proposed project execution risk and help the project in the Bid Evaluation process. In addition, the Bidder must include firm and binding milestone events and dates (including COD) with the Financial Bid. There will be no negotiation of these dates once the Financial Bid is submitted even if the Supplier cannot secure an EPC contract on a timely basis.

3.19 Question

Can parties with dissimilar assets aggregate their offering into one bid? For example, can two bidders team up to submit one bid for a baseload plant in one location and a peaker in another?

If there is a joint venture that has two projects, the bidders can bid both projects as one aggregated bid (taking the risk that it may not be selected because one component of the aggregate bid was less attractive in the scoring process and therefore weighted down the entire proposal) or they can bid the two projects separately. The RFP, however, does not allow for bidders to submit two projects separately, which are contingent on the selection of both (i.e, where the bidder states that project A can only be selected if project B is also selected).

3.20 Question

How detailed do Project Descriptions need to be? Do we need to submit detailed customer and site information or can we be more general, such as 30 MW DR in SWCT?

The Project Description form and excel template are quite detailed and need to be filled out in detail and completely. If bidders think there are questions that do not apply to their project, they should contact the RFP Coordinator in advance so that they are not disqualified for submitting incomplete forms.

3.21 Question

It is indicated that demand response resources must not be enrolled in other programs. Because the ISO-NE/CT SUPPLEMENTAL DR programs are slated to end in 2008 (though they may be extended through 2010), can resources enrolled in these programs be included in the RFP after the ISO-NE DR programs end?

Yes. Bidders can thus submit a bid for a Contract Term that starts with a date after which their existing funding has expired. However, bidders cannot submit a date-uncertain or quantity-uncertain Proposal. Bidders must commit to a date and capacity level (although that may be scheduled to ramp up or down over time) up front even if there is uncertainty on the expiration date of their current contract or funding.

3.22 Question

Will the DPUC accept bids based only on natural gas only with no alternative fuel?

Please elaborate on back-up fuel requirements for small natural gas generation less than 5 MW. This may be a burden on grid connected distributed generation.

The DPUC will not select a generation project that is solely gas-fired (and without back-up alternative fuel), with the exception of a distributed generation resource that is less than 5 MW and that bids into the RFP under the Master Agreement for Demand Resources. The Master Agreement for Demand Resources does not have an alternative fuel requirement. All other gas-fired generators would be required to provide an explanation for how it will procure and store its alternative fuel as part of its Qualification package in order to advance in the bid evaluation process. The requirement to maintain sufficient alternative fuel on-site will be legally binding in the Master Agreement for Generation.

3.23 Question

It would appear that Southwest Connecticut is where the majority of FMCCs are located? Is there no value to the Department outside of this area?

The DPUC is seeking resources across all of Connecticut. Because of the anticipated structure of the FCM (and also the anticipated supply-demand balance in Connecticut for resources qualifying for the LFRM), there are potential benefits to ratepayers from new or incremental resources located outside of Southwestern Connecticut. The Forward Capacity Market is, at this point, anticipated to be Connecticut-wide, and thus a resource that is electrically located within Connecticut will qualify on an equal footing with a project located in Southwestern Connecticut. That being said, there are benefits to siting in Southwest Connecticut that have been enumerated by ISO-NE several times.

3.24 Question

Will a list of registered bidders be published?

Neither the RFP Coordinator nor the DPUC is officially publishing a list of registered bidders. However, the registration submissions of those bidders that did not apply for confidential treatment are available on the DPUC website in this docket.

3.25 Question

Will feedback be given on bidder qualifications prior to December 13, 2006? If not, why the earlier deadline?

Yes, the RFP Coordinator will respond to bidders about whether or not they have qualified to submit a Financial Bid, as is described in the RFP.

3.26 Question

Will the team consider a bid from a Demand Resource that provides capacity only in the summer and is unable to participate in the FCM because of annual availability requirements? If so, will payment be monthly or annually? Will the Contract be for fixed payments or a CfD?

The intent of this procurement process is to have, if possible, selected projects directly participate in the ISO-NE Markets. If this project falls within the class of resources that ISO-NE has recognized as qualifying as a resource for the FCM, then it must participate in the FCM and meet all the requirements of the FCM, including those related to availability and performance. If a resource, based on its general classification, cannot participate directly in the FCM but produces benefits for Connecticut ratepayers, then it will be granted a Contract that pays the Supplier the Annual Contract Price, without settlement against the FCM.

3.27 Question

Is there a bias against small bids?

There is no minimum size requirement in this RFP process, in contrast to the more sizable minimum capacity amounts in other RFPs.

4 Contract-specific

4.1 Question

If an applicant establishes by way of an appraisal the value of a property, can an applicant post in lieu of cash or a letter of credit (the 25 dollars per KW), and instead give a mortgage on a building which would be in recordable form?

A mortgage is like a lien, which is not an acceptable form of security in this RFP process. Moreover, such a form of security would probably also be problematic for the electric distribution companies under the existing statutes, as it may give them a de facto interest in electric generation facilities.

4.2 Question

Section 3.3(b) of the Generator Contract template would require Suppliers to bid into the FCM for a one-year Contract. Based on their projected commercial operation dates,

some projects will be eligible to receive five-year FCM Contracts. Would the DPUC allow Suppliers with Contracts awarded in this RFP to bid for a full five-year FCM Contract?

The FCM/FCA rules would allow a new resource to obtain a commitment period for up to five years. As we understand it this RFP would require a new Demand Resource to offer a price for only one year/commitment period and thereafter be an existing resource. The other allows you to be a multi-year price setter but the Contract says you may be a setter for only one. What shall it be?

Because the Contract awarded under this RFP provides revenues for periods as long as 15 years, the DPUC does not want, nor do they believe it is necessary, for New Capacity to bid for the five-year term option in the FCM. The five-year Contract option in the FCM essentially provides an opportunity to secure investment capital for a sufficiently long term so as to provide an opportunity for financing these new projects. Since the DPUC is already doing that in this RFP process, there is no need for New Capacity awarded a contract under this RFP to bid for the five-year option in the FCM.

4.3 Question

The Contract settles against summer claimed capability. How will settlement work for projects with higher winter claimed capability?

Because the Contracts are settling against the FCM, which itself settles against a resource's summer seasonal claimed capability, the DPUC will remunerate the resource for the amount of its Contract Quantity which has been proven to be equal to or less than the resource's summer claimed capability (which may change from time-to-time based on ISO-NE audits of Claimed Capability, as described in Section 2.5 of the Master Agreements). Additional capacity above and beyond the summer demonstrated capacity will not be subject to settlement under these Contracts. However, the Supplier can sell this capacity directly into the relevant ISO-NE Markets (or bilaterally or to other markets) without any restriction.

4.4 Question

The relationship between Demand Resource penalties/incentives at the ISO-NE may be out of sync with the opportunities in this program because the ISO-NE performance incentives/penalties for ODR are only available if someone else pays performance penalties. In this program under the Contract terms the Buyer makes up the difference in this program. Which is the case?

The intent of the DPUC Contract is not to have ratepayers pay for "capacity" that ISO-NE has effectively not recognized because of bad performance. Therefore, as described in Section 6.4 of the Master Agreement for Demand Resources, the payment amounts to the Supplier by the Buyer will be trued-up or down for underperformance by the Supplier at ISO-NE.

4.5 Question

Please provide clarification on the \$200/kW Penalty (Page 19 of DR Contract).

This liquidated damage is a one-time payment that the Supplier would have to pay the Buyer (for the benefit of ratepayers) if its capacity was less than promised in its Financial Bid and the damages will be charged based on the deficiency (per kW) vis-à-vis the Contract Quantity promised in the Proposal. These liquidated damages are payable because Connecticut ratepayers had anticipated having that capacity in place and will now need to secure replacement capacity for the Term of the Contract.

4.6 Question

Two types of project will likely be bid as new generation – those being combined cycle and gas turbine peakers. Since the peakers are primarily needed to meet summer peak demand conditions and not likely to be required for winter operation, why could these peaker projects be required to include alternative fuel back up? This adds to the economic burden of peaker projects, reducing the number of applicable sites and will require alternative fuel to be consumed leading to extra emissions that would not have resulted except for this requirement for alternative fuel.

The alternative fuel requirement is an important and integral part of the Contract. Even if a peaker does typically run in the summer, to the extent that there is an unforeseen winter weather season, the DPUC would expect peakers to be able to operate during those periods as well to secure the reliability of the system. The alternative fuel requirements are specifically geared at those kinds of unpredictable cold snap weather conditions.

4.7 Question

Will Suppliers with multiple units participating in ISO-NE Markets continue to be permitted to handle settlement through a single agent? If so, how will the Contract unit specific bid information be confirmed?

ISO-NE does provide agents with settlement documents on an asset-specific basis and as such Suppliers will be able to continue to handle settlement through a single agent for any assets that are granted a contract under this RFP.

4.8 Question

In Section 12.6 of the Contract regarding changes in the market rules, why has the Contract departed from the more traditional change of law provision which allows the parties to renegotiate provisions to restore the economic balance of the Agreement where a change in law rule might adversely impact the ability of the Supplier to perform or materially increases its costs, such that the economic balance of the Agreement is disturbed?

The DPUC acknowledges that interested parties have raised a number of concerns related to Section 12.6 of the draft Master Agreement for Generation. The DPUC is considering how to amend the language in this section.

5 Performance-related

5.1 Question

Section 3.2(d) of the Generator Contract template references Summer Seasonal Claimed Capacity. What methods or tests will be used to determine Summer Seasonal Claimed Capacity? What conditions will be used for these tests? For example, will conditions of 90 degrees Fahrenheit and 45% humidity be used as the tests conditions?

The idea behind these requirements is that the DPUC wants the capacity that ISO-NE has certified as qualified for their markets (specifically the FCM) to be the designated Contract Quantity in the Agreement. As defined in the draft Master Agreement for Generation (Section 2.5), the Summer Seasonal Claimed Capability will be based directly on ISO-NE's summer ratings for generation facilities, which is governed by the Claimed Capability Audits (CCA) that ISO-NE administers seasonally. The procedures for the Capability Audits are described in ISO-NE's Manual 20. If there are more questions on this issue, the DPUC would recommend that bidders contact ISO-NE directly regarding their testing methodologies.

5.2 Question

The heat rates of certain units (e.g., combined cycle generators) change as they ramp up production. Will combined cycle projects have an opportunity to be evaluated at the intervals of their heat rates?

We will be asking in the Project Description templates that Bidders provide their best available information on the technical parameters of their project. Such information will be the basis for measuring the impact of a project on benefits and costs to ratepayers and will also be embodied in Exhibit A and C to the Contract (i.e., Master Agreement for Generation) if the proposed project is selected. Bidders can choose to provide the heat rate specifications as a single number or as a heat rate curve. In the Bid Evaluation process, up to three points of production and heat rate levels, ranging from minimum stable generation to maximum dependable output (Summer Seasonal Claimed Capability) will be used. Under the Master Agreement for Generation, the entire heat rate curve will be used to conduct the heat rate tests, if specified by the Bidder in their proposal.

The guidelines described in the draft Master Agreement for Generation describe the required heat rate testing methodology (see Section 3.4 (d) of the Agreement) by which an annual heat rate test will show that the Facility's thermal efficiency (otherwise known as the heat rate of the Facility) has not fallen more than 10% below the Manufacturer's Warranted Heat Rate ("MHR") provided in Exhibit C of the Agreement. The MHR is usually specified not as a single operating point, but rather as a performance curve. It would be common for a manufacturer to warrant a performance curve at "site" conditions. The warranted curves themselves are derived from the factory test bed performance curves which are corrected by the manufacturer to reflect operating conditions (and if required and/or relevant, system operator dispatch procedures) and then modified to reflect actual site elevation, etc.

The annual heat rate test procedures and results must be acceptable to the Buyer. It is expected that American Society of Mechanical Engineers (ASME) compliant test procedures will account

for part load operation as well as actual atmospheric conditions at the time of each Facility test (as compared to the Manufacturer's Warranted Heat Rate), because it is standard practice for test procedures (as guided by ASME) to prove that the facility is operating according to its warranted performance curve while taking into account load condition and atmospheric conditions during the test. Bidders should receive specific information from their facility manufacturer regarding the appropriate detail for conducting an ASME compliant heat rate test.

5.3 Question

Many of the damages provisions contain liquidated damages that appear to be unrelated to any actual damages, yet the Supplier is asked to agree that the damages are reasonable and not disproportionate to the Buyer's actual damages. Is there any data that the DPUC can supply that would help the Supplier satisfy itself that the damages are reasonable?

We have strived to create liquidated damages provisions that are reasonable and yet also serve the purpose of incentivizing Suppliers to meet their contractual obligations. As a general proposition, the standard in the electricity sector industry is that when an entity does not perform, it is required to make its counterparty "whole". The DPUC has been guided by that principle in developing the Contract templates and has carefully weighed the financial burden on the Supplier against the economic losses that ratepayers would suffer as a result of under-performance by the Supplier.

There are two categories of liquidated damages in the Contract. The first pertains to damages for making the Commercial Operation Date at the required Contract Quantity. This category is important as the COD is used as an input for the Bid Evaluation; thus, projects are being selected based on their ability to be in place and affecting the market as promised. While there are liquidated damages for intermediary milestones before COD, these are all refundable if the COD is achieved. This exemplifies the fact that the DPUC is not trying to create an onerous burden on Suppliers; the DPUC just wants to ensure that the project comes on-line as proposed and promised to Connecticut ratepayers. The liquidated damages for having an insufficient amount of Contract Quantity, as compared to what was promised in the Financial Bid, has been set very conservatively and is based on fraction of the replacement cost of that capacity as well as the opportunity costs to Connecticut ratepayers in terms of expected economic losses if the promised capacity does not materialize (taking into account that it takes time to build new replacement generation or demand resources, as relevant).

There are also liquidated damages due to underperformance of the project, in addition to penalties incurred in ISO-NE. These additional charges are due to the long-lived nature of these Contracts, as compared to the one-year timeframe of the ISO-NE's FCM. In selecting projects, the DPUC is effectively relying on the contracted quantity of capacity for the entire term of the Contract. Therefore if Contract Quantities decline during the Term of the Contract, ratepayers suffer economic losses. In addition, the Master Agreement for generation contemplates Availability Deficiency liquidated damage. This performance requirement was designed to ensure that the expected energy market benefits that ratepayers are relying on actually materialize.

5.4 Question

If a facility has an outage during one month (for example, for scheduled maintenance), will that facility be permitted to make up the outage in succeeding months? Does that answer change if the outage is unplanned?

With respect to potential penalties that generation projects would be exposed to if they were not able to perform once they had begun operation, there does not appear to be any allowance possible for planned outages for maintenance and the like. Should not such an allowance be made? What about with respect to unplanned outages?

The DPUC would like bidders to tell the DPUC when they will be available (and at what levels for any period of the Term) in the Project Description templates as part of Appendix H. As part of the terms of the Master Agreement for Generation, Suppliers are then required to meet these expectations. Availability means “the capability of a resource, in whole or in part, at any given time, to produce and supply energy, Capacity, or ancillary services in accordance with accepted electric industry practice”, as defined in the Master Agreement for Generation, and Bidder’s Target Availability is anticipated to be inclusive of both maintenance and forced outages.

The “availability schedule” provided in the Project Description Templates will help the DPUC analyze the bids in the Bid Evaluation process, and will subsequently be used if the project is selected throughout the Term of the project’s Agreement. Obliging the Supplier to maintain its promised Target Availability throughout the term of the Agreement is important as this ensures that the anticipated energy benefits that the project was selected for are in fact being realized for Connecticut ratepayers.

Thus, bidders can and should bid Contract Quantities and Availability parameters that are adjusted for expected (maintenance) and forced outages on an annual basis. Bidders can file different Contract Quantities through the duration of their Terms. Bidders are also required to file Target Availability figures, which can also change from year-to-year during the Term. As such, the Bidder can incorporate the impact of planned and unplanned outages into its scheduled capacity for the Agreement Term.

The requirements on the Supplier in the Master Agreement for Generation regarding availability are not meant to be onerous. Other than the monthly adjustment factors in the payment settlement process as discussed in Section 6.4 of the Master Agreement for Generation, the Contract does not contemplate tracking a Facility’s outages on a month to month basis, although that does not exempt the Facility from meeting ISO-NE Market Rules and paying ISO-NE penalties that may be levied for unavailability. Pursuant to Section 3.4 of the Master Agreement for Generation, the Supplier will need to report GADS data to the Buyer. The GADS data is intended to be used only for the annual Availability Deficiency performance test.

5.5 Question

Target availability is really based on your maintenance schedule and your maintenance schedule will vary according to how many hours you operate annually. But by requiring us to put in an annual availability based on maintenance then we would have to know how much we’re going to run, and that’s an unknown. So, requiring an annual availability number is less appropriate than using maintenance based on hours or availability based on hours of operation.

The DPUC acknowledges that the Supplier will not know the exact timing or amount of maintenance necessary for every year of its Contract Term, however, the DPUC is confident that a bidder can arrive at a relatively accurate estimate based on the type of generation resource and its expected operating regime – developers and manufacturers in New England and other jurisdictions routinely analyze and provide such performance targets in other Power Purchase Agreements. In conjunction with the fact that a bidder can schedule varying amounts of capacity as the Contract Quantity and a different target Availability per annum, the Department believes that this requirement and representation is not overly burdensome.

The Target Availability will be used for Bid Evaluation (to set the maintenance and forced outage levels appropriately in our analysis of a project's impact on the ISO-NE Markets) and it is a defined term for purposes of the Contract for measuring performance so the Department can rest assured that the Supplier produces the benefits that ratepayers expected to have secured from this Contract in the energy market. For purposes of the performance requirement, the Target Availability has an additional cushion of 5% per annum before Availability Deficiency is declared and liquidated damages are deemed payable. This latitude was explicitly introduced to soften the financial burden on Suppliers and to account for some of the uncertainty in the estimates.

5.6 Question

Is the term "deliverable" intended to convey anything beyond qualifying for the Local Source Requirement (LSR)?

The ISO-NE Market is a financial one and to the extent that there is any concept of deliverability of energy, it's through financial congestion. To the extent that you are including the concept of physical delivery in the Contract, that may be perceived as requiring a resource to protect against a result that it has no control over.

The LSR defines the concept of deliverability for the FCM but the DPUC uses the word "deliverable" in the RFP explicitly in reference to electrical output (i.e., Energy) – see definition in Article 1 of the draft Master Agreement for Generation. Although ISO-NE does not apply this standard for Minimum Interconnection approvals, the DPUC wants to apply this standard in this RFP as energy is a key FMCC component that the DPUC is trying to minimize. As such, the DPUC is assessing projects' energy benefits.

For this reason, a project's deliverability is being assessed in the Bid Evaluation process. The DPUC will analyze whether or not a project is deliverable from an energy perspective, using an industry-wide standard methodology to assess generator deliverability based on load flow cases and network modeling, which is commonly used by developers to understand the economics of their projects. These studies will predict whether the electrical energy from a given generator can actually be delivered into the system and serve Connecticut loads. The DPUC will conduct such additional analyses (based on submitted information by bidders in the Project Description templates) to the extent needed to ensure that selected projects will be able to reliably deliver their assumed capacity and therefore produce energy benefits.

In addition, the concept of deliverability is also used in a limited fashion in the draft Master Agreement for generation. In Section 3.2 (g), the contract states that the Supplier must not undertake any action or fail to perform any necessary task such that energy output from the

project is not deliverable in Connecticut. Thus, the DPUC is not requiring as part of the Contract that resources physically deliver energy, but that they do nothing to render the energy output from their facility undeliverable, so that ratepayers realize the expected benefits from the energy market that were included as the justification for selecting the project in the first place. Thus, the Supplier's responsibility as per the terms of the contract are indeed under his control.

5.7 Question

Given that the monthly payment adjustment ratio in Section 6.3 of the Agreement incorporates any unavailability penalties assessed to Suppliers in the FCM or LFRM, doesn't the inclusion of additional availability penalties in Section 3.1(c), Section 3.2 (d), Section 3.2 (e), and 3.4 (c) build in more Supplier risk and risk premiums into the Financial Bids?

Section 6.3 refers to the ISO-NE performance requirements within ISO-NE's seasonal or one year commitment period time-frame. The terms of the penalties that ISO-NE may impose are quite different from what we have incorporated in this Contract. The performance requirements and liquidated damages in the Master Agreements are focused on preserving the integrity of the resource's capacity level and performance for the entire Term of the Contract, as this capacity and performance is what Connecticut ratepayers are paying for.