David I. Poch Barrister tel. (613) 264-0055 fax (613) 264-2878

09 May 2008

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms Walli:

Re: EB-2007-0905 GEC-Pembina-OSEA IRRs

Attached please find Ex. M-7.0, our responses to IRs from OPG

Sincerely,

David Poch

1649 Old Brooke Road, Maberly, Ontario K0H 2B0 e-mail: dpoch@eelaw.ca

Ontario Power Generation Inc. ("OPG")
<u>Interrogatories for GEC</u>

INTERROGATORY #1

Ref: Page 3, lines 10 - 13

Preamble: Mr. Chernick concludes "that the Board should set separate costs of capital-that is, cost of equity and capital structure-for each of OPG's operational segments, both to facilitate the tracking of costs and to improve OPG's decision-making with regard to investments."

Interrogatory

a) Does Mr. Chernick believe that the regulated wires and generation lines of business of an integrated electric utility have different costs of capital? Please explain in detail.

b) Would Mr. Chernick please confirm that state regulators in the U.S. generally allow a single ROE and capital structure for the composite regulated transmission, distribution and generation operations of integrated utilities? If he cannot confirm, please explain in detail why not.

c) Would Mr. Chernick please explain how he envisages separate cost of capital rates for OPG's nuclear and hydro operating segments being applied. In this explanation, please specifically comment on the determination of revenue requirement, the allocation of corporate capital budget amounts, the determination of service charges and the allowance for funds used during construction.

Response

a) Yes, see discussion under (b) below.
b) That is the traditional approach. In general, transmission rates are now set by FERC based on FERC's determination of cost of capital for that service. In several states, utilities do not have generation assets, so distribution rates are set based on distribution cost of capital. In its pending acquisition of peaking capacity under cost-of-service rates, the Connecticut DPUC has allowed distribution utilities to apply for a generation return that is higher than its distribution return; Connecticut Light and Power has proposed projects using a higher return.

c) The revenue requirement would be computed to include the rate base for each service, times the rate of return for that service. I am not familiar with the phrase "allocation of corporate capital budget amounts." Assuming that the phrase refers to decisions to budget capital to the various lines of business, I envision that OPG would evaluate capital investments based on the allowed cost of capital for the relevant line of business. I have not reviewed OPG's development of service charges; I am not aware of any aspect of that development that would be changed by the use of service-specific costs of capital. AFUDC should be computed based on the cost of capital for the relevant service.

Ontario Power Generation Inc. (“OPG”)
Interrogatories for GEC

INTERROGATORY #2

Ref: Page 9, lines 18 – 25

Preamble: “When the risks of an investor-owned utility are shifted to ratepayers, the utility’s return should generally be reduced. But for OPG, as a provincial entity, a return on equity that reflects the underlying risks has two advantages. First, the higher return will increase OPG’s retained earnings when all goes well, allowing OPG to absorb more of the costs of adverse outcomes when they occur. Second, since OPG will use the return set by the OEB in evaluating investments, it is important that the return on nuclear investments include as much of the nuclear risks as feasible.”

Interrogatory

a) Please explain why the two advantages set out at lines 20 - 25 do not apply equally to investor-owned utilities.

b) If the OEB wanted to establish payment amounts that meet the standard of being “economically efficient”, should the risks that have been “transferred to ratepayers” be included in the OEB’s determinations of OPG’s ROE and capital structure?

c) Is there a difference between establishing a nuclear rate of return that is “appropriate” in that it reflects the nuclear operational and financial risks remaining after consideration of relevant approved risk mitigation proposals, and establishing a rate of return that reflects “as much of the nuclear risks as feasible.”?

Response

a) In general, the first factor would not apply to IOUs, which have no obligation or incentive to use shareholder retained earnings to cover the “costs of adverse outcomes when they occur.” Indeed, IOUs generally pay out much of their earnings as dividends, which are no longer available to the corporation to offset costs. The second factor would apply.

b) I am not clear what the question is suggesting. I believe that the full cost of the resources used by customers should be charged to them.

c) Yes. However, I am recommending a regulatory approach to preserve the beneficial effects of risk based capital costing while recognizing the transfer of risks inherent in the mandated deferral accounts.

To be clear, my preference is that risks be retained by the utility. Apart from those matters where Regulation 53/05 requires the transfer of risk to the ratepayers, it is my recommendation that deferral accounts be avoided so that the corresponding increase in the allowed return better reflects the true risk of OPG's business activities.

Where deferral accounts are mandated, I am not proposing double recovery. For risks covered by deferral accounts, customers will bear the cost of adverse outcomes in any scenario. The issue is whether OPG should be reimbursed for having incurred an expense after the fact or be compensated in advance. My recommendation is that they be compensated in advance by way of a cost of capital reflecting the risk so that they can better gauge the desirability of incremental investments. If the Board adopts my recommendation it would be appropriate to track the added retained earnings and offset these against any subsequent costs that are eligible for deferral account treatment (by a corresponding reduction in the return at that time).

As I discuss in my evidence, this would not be a suitable approach for a private entity as there would be no assurance that the retained earnings would be available and the lower return at that time could be challenged as 'unreasonable'. However, for a 100% publicly owned entity it is a feasible approach that shields OPG against sudden misfortune (the presumed intent of the regulations) while maintaining the salutary effects of a return more accurately reflecting the real business risks.

Ontario Power Generation Inc. ("OPG")
Interrogatories for GEC

INTERROGATORY #3

Ref: Page 10, lines 4 – 14

Preamble: "Ms. McShane's estimated cost of capital for OPG's hydro operations is about 8 percent, which is similar to the costs of capital embedded in the bids in the current procurement of peaking capacity under cost-of-service contracts conducted by the Connecticut Department of Public Utility Control (Docket No. 08-01-01). Bidders were allowed to offer costs of equity up to 10.75 percent, indexed to allowed utility ROE (but with a 9.75 percent floor), and up to 60 percent equity. Bidders offered ROEs from 9.75 percent to 10.75 percent, and equity of 40 percent to 50 percent. With a 6 percent debt cost, these bids are equivalent to 7.8 percent to 9.1 percent overall return. The bids that have been recommended by experts for the Department and the Office of Consumer Counsel (including me) offered returns equivalent to 8.2 percent to 8.6 percent."

Interrogatory

a) Please provide a copy of the documentation that supports the referenced costs of equity and equity ratios that bidders were allowed to offer.

b) Please explain in detail how the referenced costs of equity tie to the allowed ROEs of the electricity distributors in Connecticut.

c) If not included in the responses to a) or b), please explain in detail what "indexed to allowed ROE" means in the context of the bids.

d) Please explain whether the costs of capital contained in the bids were a determining factor in Mr. Chernick's recommendations to the DPUC.

e) Please explain how the range of 7.8 percent to 9.1 percent was arrived at given the referenced ROEs and capital structures of the bids.

Response

a) See attachment 1: the order in Connecticut DPUC Docket No. 07-08-24, especially pages 32–35.

b) See (a).

c) See (a).

d) The costs of capital contained in the bids was one of many components contributed to the fixed revenue requirements, which was compared to various benefit streams (capacity, reserves, and energy revenues, and effects on market prices) and non-quantified factors, such as probability of project completion.

e) See attachment 2.

Peaking Project Costs and Characteristics

	Bridgeport Energy II			CL&P			GenConn					
	Option 1	Option 2	**BPP**	Lebanon	Waterbury	**FirstLight**	Option 1	Option 2	Option 3	Option 4	**Maxim**	**PSEG**
COD	11/30/2010	11/30/2010	5/31/2010	5/31/2010	1/31/2010	4/1/2011	6/1/2010	6/1/2010	6/1/2010	6/1/2010	6/1/2012	6/1/2011
Summer MW	314	360	180	156	56	94	469	376	281	188	93	133
Units	2	2	1	4	2	2	10	8	6	4	2	3
Primary Fuel	NG	NG	NG	Diesel	NG	NG	NG [1]	NG	NG	NG	NG	NG
TMNSR	No	No	No	Yes	Yes	Yes	No [2]	No [2]	No [2]	No [2]	Yes	Yes
FCA Eligibility	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2012	2011
Black Start Capability	No	No	Add $500k	Add $500k	Add $500k	Yes	Add $1.5M	Add $1M	Add $1M	Add $500k	Add $1.5M	Yes
Capital Cost (mixed $/summer kW) [3]	1,204	1,101	824	1,157	1,390	1,449	1,087	1,066	1,107	1,046	1,292	1,064
Fixed O&M (2008$/summer kW-yr) [4]	8.74	7.62	35.52	24.84	39.13	18.15	18.96	19.57	20.35	21.53	23.65	14.10
Assumed Expense Escalation	2.50%	2.50%	2.50%	Various escalators	Various escalators	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
ROE	10.25%	10.25%	10.75%	10.50%	10.50%	10.40%	10.25%	10.25%	10.25%	10.25%	9.75%	10.75%
Equity %	50.00%	50.00%	40.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	40.00%	40.00%
Assumed Debt Rate	6.95%	6.95%	8.00%	6.19%	6.19%	7.26%	6.65%	6.65%	6.65%	6.65%	6.50%	6.50%
Debt %	50.00%	50.00%	60.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	60.00%	60.00%
Wtd Cost of Capital	8.60%	8.60%	9.10%	8.35%	8.35%	8.83%	8.45%	8.45%	8.45%	8.45%	7.80%	8.20%
Levelized AFRR ($/summer kW-month)	**$13.65**	**$12.37**	**$12.42**	**$14.78**	**$19.88**	**$17.87**	**$12.76**	**$12.68**	**$13.17**	**$12.79**	**$17.95**	**$12.49**
CL&P Levelized AFRR w/o A&G				$13.29	$18.13							
Incremental Levelized AFRR for Monville Addition							$13.09					

[1] Ultra-low-sulfur distillate for Montville units.
[2] GenConn units capable of providing TMNSR, at DPUC direction. (Response to PRO-113)
[3] Capital cost includes AFUDC.
[4] Fixed O&M includes insurance, excludes taxes.

STATE OF CONNECTICUT

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

DOCKET NO. 07-08-24 DPUC INVESTIGATION OF THE PROCESS AND CRITERIA FOR USE IN IMPLEMENTING SECTION 50 OF PUBLIC ACT 07-242 - PEAKING GENERATION

December 14, 2007

By the following Commissioners:

Donald W. Downes
Anne C. George
John W. Betkoski, III

<u>DECISION</u>

I. INTRODUCTION

A. SUMMARY

Section 50 of Public Act 07-242, An Act Concerning Electricity and Energy Efficiency, directs the Department to conduct a contested case to review proposals to build new Connecticut peaking generation units that will be paid cost-of-service rates. The Department is required to approve all proposals unless it finds that a proposal is or proposals are not in the interest of ratepayers. The Department opened this uncontested proceeding to develop the process and criteria that it will use to review peaking project proposals in the future contested case.

In this Decision, the Department 1) provides the contested case schedule, 2) determines, subject to further review in February 2008, that there is a peaking generation need of five hundred (500) megawatts (MW) of new peaking generation, 3) identifies the criteria the Department will use to evaluate the proposals, 4) describes the information that must be provided in the proposals for them to be deemed complete and 5) approves a standard contract for use with merchant generator projects. The Department finds that this information is necessary for it to conduct and complete the contested case within the one-hundred-twenty day timeframe established by Section 50 and so that filers will know when to file, what information needs to be filed for their proposal to be complete, and how the proposal will be evaluated so that the proposal can address how it meets the selection criteria.

B. BACKGROUND OF THE PROCEEDING

Section 50 of Public Act 07-242 (Act) directs the Department to receive, review and approve, approve with modifications, or reject proposals to build peaking units within 120 days of its receipt of complete proposals. The Department is required to approve all proposals unless it demonstrates, based on the principles of General Statutes of Connecticut § 16-19e (Conn. Gen. Stat.), that a proposal is not in the interest of ratepayers. Section 50 also requires that the Department: 1) consistent with the principles of Conn. Gen. Stat. §§ 16-19, 16-19b and 16-19e, approve cost of service plans and set a return on equity (ROE) for approved projects; 2) establish guidelines for the approved projects' participation in the ISO New England (ISO-NE) markets; and 3) establish procedures that approved projects must follow for future contested annual retail rate cases governing the peaking units.

The Department opened this uncontested proceeding to receive information that will assist it to conduct the future contested case proceeding pursuant to Section 50 and to develop the process and selection criteria to be used by the Department in the Section 50 proceeding.

In order to determine how much peaking generation to procure and at what cost, Section 50 and Conn. Gen. Stat. § 16-19e require that the Department make determinations about: 1) how much peaking generation is needed; 2) the prudent capital and operating costs of peaking generation; 3) the ROE for such projects; 4) whether a proposed plan is, or is not, in the interest of ratepayers. The purpose of this proceeding is to receive information and input from docket participants on these issues to assist the Department in conducting the Section 50 procurement. The Department also seeks input on any other substantive or process issues participants wish to make recommendations on related to Section 50.

C. CONDUCT OF THE PROCEEDING

By Notice of Scope of Proceeding and Request for Written Comments dated September 5, 2007, the Department requested detailed written comments on the Section 50 requirements. By Notice of Hearing dated October 4, 2007, hearings were scheduled and on October 26 and 29, 2007. The October 26, 2007 hearing was held and the October 29, 2007 hearing was canceled.

By Notice of Rescheduled Hearing dated October 30, 2007, the Department rescheduled the late filed exhibits hearing in this matter to November 9, 2007 when it was held.

D. PARTICIPANTS

The Department recognized AARP, 21 Oak Street, Suite 104, Hartford, CT 06111; Blue Sky Environmental, 105 Chestnut Street, Suite 37, Needham, MA 02492; Bridgeport Energy II (BE II), LLC, 280 Trumbull Street, Hartford, CT 06103-3597; the Connecticut Industrial Energy Consumers (CIEC), 540 Broadway, Albany, New York 12207; Pinpoint Power, LLC (Pinpoint), 105 Chestnut Street, Suite 37, Needham, MA 02492; Northeast Utilities Service Company/The Connecticut Light and Power Company (CL&P), P.O. Box 270, Hartford, CT 06141-0270; FirstLight Power Resources, Inc. (FirstLight), 20 Church Street, 16th Floor, Hartford, CT 06103; GE Financial Services, Inc. (GE), 120 Long Ridge Road, Stamford, CT 06927; ISO-NE, One Sullivan Road, Holyoke, MA 01040-2841; Kleen Energy Systems, LLC (Kleen), 90 State House Square, Hartford, CT 06103; LS Power Associates L.P./LS Power Development, LLC (LS Power), 400 Chesterfield Center #110, Chesterfield, MO 63107; NRG Energy, Inc. (NRG), 211 Carnegie Center, Princeton, NJ 08540; Office of Consumer Counsel (OCC), 10 Franklin Square, New Britain, CT 06051; Prospero, LLC (Prospero), 20 Marshall Street, Suite 300, Norwalk, CT 06854; Pure Power, 406 Farmington Avenue, Farmington, CT 06032; and The United Illuminating Company (UI), 157 Church Street, New Haven, CT 06506-0901 as Participants in this proceeding.

II. PARTICIPANT SUBMISSIONS

In response to the Department's Request for Written Comments, written comments were received from AARP, CL&P, FirstLight, LS Power & BE II, New England Power Generators Association, Inc., NRG, Pinpoint, Retail Energy Supply Association/Constellation Energy/Constellation New Energy, OCC and UI. These comments were discussed during the Hearings on October 26, 2007 and November 9, 2007. Following is a short summation of post-hearing Briefs filed by certain Participants on November 14, 2007:

A. BRIDGEPORT ENERGY II BRIEF

1. Plan Requirements

BE II emphasized that the Department's plan should require that the EDC's submissions should be subject to all of the same requirements as plans submitted by other entities. Specifically, any cross-subsidization from an EDC's Transmission and Distribution (T&D) businesses must be avoided to ensure all participants are playing on a level playing field. BE II recommends that the EDCs establish separate entities for their proposed projects. Further, the Department's provisions regarding performance obligations and nonperformance penalties should be the same for all projects.

2. Cost Recovery

The Department should allow alternate pricing structures to be bid rather than being solely rate of return regulation, such as price cap regulation, revenue regulation, performance based regulation (PBR), or a combination thereof. The initial pro forma financial statements can be used to establish the initial cost of service, and compared to actual cost of service, with the annual adjustment recovered in the following year. The potential risk impacts of the timing and cost of construction, availability and performance of the facility, and Operations and Maintenance (O&M) timing and costs can be reduced through measures including cost overrun restrictions, performance assurances and performance measures. Various methods were proposed to reduce risks and assess penalties.

3. Department Requirements

The Department should not be prescriptive regarding the type of fuel, type of equipment and type of pricing arrangements that would apply to each project. BE II then recited principles the Department should strive towards, and a shopping list of "other criteria" the Department should consider in evaluating project benefits besides least cost. In this regard, BE II mentioned: cost estimate reasonableness and overrun protections; project benefits; project execution risk and performance guarantees; interconnection fitness; participation in ISO-NE markets; environmental impacts; fuel sources; financing costs and project location. The Department should consider establishing a minimum threshold for achieving an estimated public benefit such as requiring a specified percentage economic savings to ratepayers over the contract term.

To assess the potential ratepayer benefit of a project, the project plans should include, at a minimum:

- Pro forma financial statements for construction;
- Pro forma financial statements for operation and maintenance (O&M) needed to operate for the purpose of meeting the locational forward reserve obligations;
- Project status regarding:
  - Site control
  - Permits and approvals
  - Fuel supply
  - Financing
  - Interconnection
  - ISO-NE market participation eligibility

4. ROE

BE II suggests that the Department evaluate the ROE on a project-by-project basis, and establish a bandwidth around it so that project financiers can better evaluate the risk that may occur over the life of the project.

5. Other Considerations

- Non-Electric Distribution Company (EDC) projects should not be treated as “public service companies.”
- Non-EDC projects should recover costs through a wholesale purchase power contract between the project and the EDC similar to a contract proposed by Pinpoint in this proceeding.

B. CONNECTICUT INDUSTRIAL ENERGY CONSUMERS (CIEC) BRIEF

The CIEC’s Brief concentrated on how Section 50 should be charged to ratepayers through a charge akin to the Generation Service Charge to allocate charges for peaking facilities in proportion to each tariff class’ respective contribution to peak demand. CIEC opposes CL&P’s current plan to eliminate interruptible rates because of its effect of increasing peak demand by reducing the load participating in demand response programs. Further, the ROE should reflect, in the case of cost of service annual true-ups, a lower level of risk compared to other merchant generating units, and disputes CL&P’s contention that peaking generator’s ROEs should be higher than the return for an EDCs distribution business.

C. CL&P BRIEF

1. Needs Assessment

CL&P states that the Department should procure 200MWs to have the Locational Forward Reserve Market (LFRM) clear below the $14 /kW-mo. penalty payment.

2. Cost of Service

CL&P suggests the Department employ periodic ratemaking involving the establishment of a revenue requirement based on:

- Rate base and a reasonable return thereon; a
- Rational capital structure; and
- Recovery of reasonable and prudent expenses including capital costs, O&M expenses, depreciation, fuel costs, taxes and other governmental charges, and a reasonable rate of return on equity.

CL&P notes that fixed cost proposals do not conform to Section 50 requirements.

3. Return on Equity (ROE)

CL&P suggests that the Department use the 10.88% established by FERC for Reliability Must Run (RMR) facilities in New England without any additional basis points adder. Alternatives include pre-establishing an ROE using an average actual ROE allowed by state commissions for distribution companies along with a premium for generation, e.g. .32 basis points for generation owned by its sister company, Public Service Company of New Hampshire (PSNH) or averaging CL&P and UI's allowed ROEs plus a risk premium. The allowed ROE must be applied to the *actual* project cost of capital rather than a 50/50 debt to equity proxy.

4. Contracts

CL&P states there is no need for a contract between EDCs and non-utility generators as long as the project owner is willing to subject the generator to annual generation rate cases under the jurisdiction of the Department, with the Department specifying its regulatory authority in any order approving a non-utility project.

5. Other Considerations

a. The generator must bid its resources into all the ISO-NE markets for the term of the procurement, with all revenues therefrom offsetting the revenue requirement with appropriate sanctions for failure to participate.

b. FERC's jurisdiction could be assuaged by the project's obtaining market-based rate authority to bid its output into the ISO-NE wholesale market.

c. Customers should receive full benefits from the projects for its full *physical* life, not just the book life or contract term.

d. Protective treatment of information should be determined by the Department on a case-by-case basis.

e. The Department should not require a project to have dual fuel capability.

f. Financial assurances should be provided (letter of credit) in case of a generator's poor performance or default/bankruptcy.

D. FIRSTLIGHT POWER RESOURCES, INC. BRIEF

1. Needs Assessment

FirstLight indicates that the procurement should stop at the point of developing projects above Connecticut's needs that might satisfy New England's total capacity market with the potential for distorting market prices. The procurement strategy should recognize the New England East West Solution (NEEWS) transmission project. The procured capacity should clear the ISO-NE Forward Capacity Market (FCM) by clearing in an FCM auction before awarding an effective contract. The Department should avail itself of the resource plan to be completed in early 2008 to determine the amount and location of capacity to be procured.

2. Cost Principles

FirstLight recommends fixed cost of service proposals, with only fuel cost being passed through as a variable cost. This would eliminate true-up recovery for estimated costs that are too low. If the Department allows cost recovery within a band, the band should be very tight, no greater than 5%, operating in both directions. FirstLight suggests using a Contract for Differences (CfD) transaction structure for pricing selected projects, i.e. bid revenue less market revenues plus fuel cost.

3. Other Considerations

a. Products should be bid into the ISO-NE market reflecting economic value.

b. The CfD payment calculation should include all products, not just capacity and LFRM.

c. Fuel costs and CfD settlement should be subject to annual review.

d. Confidentiality of information submitted with a proposal depends on Department approval; however, electrical and natural gas interconnection costs should not be protected.

e. FirstLight disagrees with CL&P's proposal that project proposers should have the status of a "public service company."

f. All projects should agree to the Department's jurisdiction for dispute resolution.

E. OCC BRIEF

1. Contract Terms:

The OCC believes that a contract is necessary, at least for non-utility generators, between such Supplier and the EDC, to allow the Department to enforce cost of service principles. The contract needs to be structured to honor the statute and protect ratepayers to the maximum extent possible by avoiding Federal jurisdictional issues while assuring compensation that reflects cost of service. The OCC listed a variety of legal observations on the jurisdictional issue. The OCC indicated that the regulatory protections afforded within title 16 provisions should be applied uniformly to non-utility generators as they would be to EDC generators, with such protections dealt with directly by the contract. Also, the costs and benefits of the Section 50 arrangements should be shared by all customers, not in standard service offers by the EDCs, but should rather be included in non-bypassable charges.

F. PINPOINT POWER BRIEF

1. Residual Value

The residual value of a project beyond the contract terms should be recognized by a mechanism such as a developer-proposed value which is excluded from rate base, thus lowering cost of service during the contract.

2. ROE

Pinpoint suggests that the debt to equity ratio should be 50/50, with an ROE standard set at a level that will attract robust proposals with the developer assuming a significant amount of the project risk.

3. Other Considerations

a. Non-utility suppliers should not be considered public service companies.

b. Contract provisions can allow the Department to be the ultimate arbiter of the wholesale contracts rather than FERC.

c. Cost of service pricing should recognize and adjust for risks related to capital cost, performance, non-fuel O&M, electric interconnection and fuel costs.

d. Since no contract has yet been agreed to, all project proponents should include a firm proposed contract with their submission.

e. EDCs establish a stand-alone entity for EDC-owned generation projects to prevent cross-subsidization.

G. UI Brief

1. Standardization

UI suggests that all plan proposals should provide for a standardized, transparent comparison between the projects.

2. Cost of Service

UI suggests using the traditional utility revenue requirements formula (O&M + Depreciation + Taxes + Return on Rate Base). All capital costs should be submitted in 2008 dollars. All costs approved in a proposal are deemed reasonable. Subsequently, costs between 100% and 115% of proposed costs are reviewable, and costs above 115% are considered unreasonable and unrecoverable.

3. Customer Benefits

UI states that the Locational Forward Reserve Requirement (LFRR) must be met to maximize customer benefits. Benefits should include environmental considerations. The Department should define how project benefits will be calculated and how quantifiable project benefits will be measured, e.g. LFRM, energy, ancillary benefits.

4. ROE

UI states that the Department should fix a capital structure at 50% debt to 50% equity for the duration of the contract. Debt cost should be specified as a fixed interest percentage at contract time or a pass-through of the generator’s actual cost of borrowing. Based on FERC’s RMR-approved benchmark ROE, UI recommends that the ROE starting point should be 10.88% plus 75 basis points. Additional risk factors should be reflected as an adder to the ROE. The Department should specify if it is requires using a fixed cost of equity or a proposed index.

5. Evaluation Criteria

UI suggests that the procurement process defines a complete plan submission, with a standardized application that includes the same categories of information. The application should serve to ensure the technical, financial and managerial expertise of project sponsors.

Technical considerations should include:

- Siting plans, reviews, and permits received and/or required;
- Air permits applied for or received;
- Environmental impacts;
- Interconnection study status; ISO-NE queue position;
- FCM status;
- Equipment type and specifications;
- Planned LFRM product; and
- A critical path schedule.

Minimum threshold requirements for project consideration should include site control, site adequacy and interconnection feasibility. Units that have near-term commercial operation dates should provide a demonstrated ability to receive state and local permits, interconnection applications submitted to ISO-NE, documentation that the project has taken steps to participate in the FCM, and a completed siting application filed with the Connecticut Siting Council.

UI suggests that the Department should further define how project benefits will be calculated and how quantifiable project benefits will be measured, e.g. LFRM, energy, ancillary benefits. The goal should be the ability to compare the net present value of a proposed plan’s costs to the net present value of its benefits.

6. Contract Issues

UI opined on a number of jurisdictional issues between FERC and the Department, specifically how contract provisions, such as the Supplier’s acceptance of being a party to periodic Department rate cases could temper FERC’s jurisdiction over the contract term.

III. DEPARTMENT ANALYSIS

A. NEEDS ASSESSMENT

1. Background

Section 50 of the Act invites the EDCs and other parties to submit plans to build “peaking generation”. The quantity and technology characteristics of the peaking generation to be procured are not specified in the legislation. Peaking capacity is generally defined as generating capacity intended to meet peak demand. Generators providing peaking capacity are normally not dispatched at capacity factors higher than 10%. There are many applications for peaking capacity in modern electrical power systems. Peaking generators operate in the capacity and energy markets as well as provide ancillary services. Providing operating reserves is one of the ancillary services where peaking capacity and, in particular, quick start capacity may be very effective. In written and oral testimony submitted in this docket, participants have generally focused on the peaking capacity requirement that has been identified by ISO-NE in the LFRM. Some participants have also acknowledged that efficient peaking generation, bid at cost-of-service rates, can also provide energy benefits by reducing Locational Marginal Prices (LMPs) during scarcity hours. Herein, the Department outlines a methodology for determining the quantity of peaking generation that can provide economic and reliability benefits to Connecticut's ratepayers. While this method is oriented around the quantity and net LFRM benefits, the opportunity for net LMP benefits is also considered.

The LFRM administered by ISO-NE is designed to procure resources capable of restoring the system after a contingency and making it ready for the second contingency. Consistent with Operating Procedure #19 and ISO-NE's operational practice, the LFRR reflects the need for additional thirty minute operating reserves to provide second contingency coverage in import-constrained locations. The LFRM is specifically intended to attract quick start resources within zones that are transmission constrained such as CT and SWCT. ISO-NE procures resources two times a year - for the eight winter months (October 1 through May 31), and for the four summer months (June 1 through September 30). Quick start generation that may be in-service within 30 minutes and online generators qualify for participating in the LFRM as Thirty Minute Operating Reserve (TMOR). Quick start resources of higher quality qualify as Ten Minute Non-Spinning Reserve (TMNSR). Currently, there are four reserve zones in New England: NEMA/Boston, SWCT, CT, and Rest of System (ROS). Each reserve zone TMOR requirement is determined prior to the auction. TMNSR is procured to meet the system requirement and is specified for ROS. ISO-NE's LFRM software automatically optimizes the results with the objective of minimizing the total costs and meeting the operating reserve requirements. As a higher quality reserve, TMNSR can substitute for TMOR if it is economically preferable.

The LFRR is determined prior to each LFRM auction. So far, ISO-NE has conducted three LFRM auctions since market inception in 2006. CT and SWCT reserve zones have consistently cleared at the market price cap equal to $14,000/MW-month because of the shortage of forward reserve resources. For example, ISO-NE determined that the LFRR in CT for Winter 2007/2008 was equal to 1,366 MW. However, only 950 MW of existing qualified TMOR resources were offered and cleared in the LFRM auction. The LFRM auction data are presented in Table 1, below.

Table 1 – LFRM Auction Results for CT (incl. SWCT)[1]

	Winter 06/07				Summer 07				Winter 07/08			
Product	LFRR MW	MW Cleared	Price $/MW-mo	Payments	LFRR MW	MW Cleared	Price $/MW-mo	Payments	LFRR MW	MW Cleared	Price $/MW-mo	Payments
TMNSR	1340	90	$14,000	$10,080,000	1055	0	$14,000	$0	1366	0	$14,000	$0
TMOR		569	$14,000	$63,728,000		725	$14,000	$40,600,000		950	$14,000	$106,400,000

Of course, operational reliability must be maintained even if the zone is short in quick start resources to provide the LFRR. The shortfall is covered through spinning reserve provided by larger combined cycle and/or steam units dispatched mostly in real-time and frequently out of merit order. The payments made to these generators to cover for second contingency are referred to as Local Second Contingency Protection Resource Net Commitment Period Compensation (NCPC) payments.[2] These payments are also generally referred to as “uplift.”

Currently, the total payments by Connecticut ratepayers for operating reserves are comprised of two major components: (1) the LFRM payments, and (2) the NCPC, or uplift payments.[3] Connecticut ratepayers currently pay $30-40 million per year in NCPC payments and a disproportionately large share of the total LFRM payments because of the shortage of peaking and other quick start resources located in-state. Over and above the reliability and environmental benefits provided, additional peaking capacity that competes in the LFRM thus has two potential impacts: reducing the LFRM clearing price; and reducing NCPC payments.

There are other potential impacts which may alter the needs assessment and evaluation of benefits. Addition of peaking generation under cost-of-service contracts may confer benefits to Connecticut ratepayers by lowering LMPs during hours of scarcity, as noted above. Furthermore, additional capacity may also lower FCM clearing prices. The Department also recognizes that the commissioning of the Kleen Energy combined cycle plant or any other new capacity in Connecticut, even if not a peaking resource, may actually lower the LFRR. This is because additional capacity in the CT zone that can be dispatched in merit order may reduce economic imports into CT and thereby may alleviate the loading on the CT interface. This, in turn, would result in more spare transfer capability being made available on the CT interface and therefore increased external support during emergencies. LFRR calculations take into account the amount of reserve support that can be imported across interfaces into the import-constrained locations. This support, which is referred to as the

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1 http://www.iso-ne.com/markets/othrmkts_data/res_mkt/summ/2007/forward_reserve_auction_results.pdf

2 The NCPC payments were formerly known as Daily RMR Resource Operating Reserve payments.

3 Real Time reserve payments have been a small fraction of the LFRM and Local Second Contingency Protection Resource NCPC payments (see page 34 of the ISO-NE Reserve Markets Report filed with the FERC on October 1, 2007 under Docket ER06-613-004).

External Reserve Support (ERS), is a probabilistically determined value analogous to the external support during emergencies. If a new resource is committed by ISO-NE for a sufficiently large proportion of hours, it may *increase* the ERS into CT, which would *decrease* the LFRR. Accordingly, the need for locational forward reserves within CT would be reduced. Even without adding new quick start resources, a reduction of the LFRR would reduce the need for committing out of merit units to provide spinning reserve, thus lowering NCPC payments (uplift).

2. Meeting the LFRR

The primary objective of the peaking capacity procurement is to obtain enough quick start resources to meet the LFRR. Any incremental amount of quick start capacity that, together with the existing qualified generation resources, does not satisfy the requirement would not lower the LFRM clearing price. Connecticut LFRM resources will continue to be paid at $14,000/MW-month even if the total quick start capacity offered in the TMOR auction is just 1 MW short of the LFRR. However, the amount of uplift costs incurred due to the shortage of the quick start capacity will gradually diminish with each increment of new quick start capacity. Uplift will be largely but not completely eliminated when the LFRR is fully met by the quick start resources. The methodology for calculating the remaining NCPC charges is explained in Attachment 1.

Hence, determination of the quick start capacity needed to reach the LFRR is the initial task. In this analysis the Department relies on historical auction data, as well as on confirmed information available regarding new entry in the near future. The Department believes that the needs assessment should not rely on any contemplated transmission expansion plans (such as NEEWS) which have not been finalized or included in ISO-NE's 2007-2011 outlook in RSP07. However, the 345 kV Phase II build-out has a planned completion date of December 2009. As a result ISO-NE has determined that SWCT will no longer be a separate reserve zone by the 2010/2011 market period.[4] Therefore, the peaking capacity need determination will be made for the entire CT reserve zone, without a separate requirement for SWCT.

Based on the most recent LFRM auction, 950 MW of TMOR capacity in CT was offered into the auction. To derive an estimate of the unfulfilled LFRR need, the Department assumes this capacity will continue to participate in the LFRM in future auctions. In addition, the Department includes the Waterbury peaking power plant (96 MW winter, 76 MW summer), which is under a long term contract through the EIA capacity procurement and will be in-service on July 1, 2009.[5] The Department also includes NRG's Cos Cob units (38 MW), which are scheduled to go in service in June 2008. Assuming the LFRR continues to be in

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[4] ISO-NE RSP07 dated 7/30/07, Table 6-1, p. 49. Northeast Utilities System recently announced that the construction project is ahead of schedule (November 5 news release)

[5] See Master Agreement between United Illuminating Company and Waterbury Generation LLC dated May 21, 2007, Exhibit B.

the range of 1366 MW, and taking into account the existing and pending resources, the Department estimates that an additional 282 MW, *i.e*., 1366 MW less 950 MW less 96 MW less 38 MW, of quick start capacity would be needed to achieve the LFRR in CT.[6] Should the Department become aware in a timely manner of other new quick start resources that have cleared in the next FCM auction to be held in early February 2008, this initial estimate would be updated. Similarly, if ISO-NE revises its LFRR, the calculation would be revised accordingly.

3. Cost-Benefit Analysis of the Initial Block

The Department has developed an analytical tool to estimate the costs and benefits associated with procurement of the first 282 MW of quick start capacity that would just meet the LFRR. The Department will use the most recent history of uplift payments as the benchmark in this evaluation. The costs and benefits of procuring the initial block of quick start capacity are determined analytically for successive 10-MW increments of capacity. Accordingly, the effect of the initial 282 MW needed to meet the LFRR is calculated as the procurement of 29 10-MW increments, i.e., 290 MW.

Including the Waterbury and Cos Cob units, The Department assumes that there will be 1084 MW winter and a corresponding 839 MW of existing summer qualified quick start resources in CT that will continue to be compensated at $14,000/MW-month until the last 10 MW of the 290 MW block of new resources is commercialized. Hence, there would be no benefit in terms of reducing payments in the LFRM to the existing resources unless the LFRM clearing price is moved down from the cap.[7] However, the primary benefit of the initial block of capacity is that it will reduce the NCPC payments to generators to meet second contingency criteria.

The Department's review of the NCPC actual data shows that these savings would be meaningful. Table 2 below shows the actual NCPC payments made to CT resources from October 23, 2005 to December 3, 2007. According to ISO-NE market rules, these costs are fully allocated to the CT reliability zone.

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6 In the event that new quick start resources clear in the February 2008 FCM auction, the Department would then make a determination of whether these resources are eligible and likely to participate in the LFRM auction, and account for this capacity accordingly.

7 Actually, there is an additional cost resulting from the contractual payments to these additional resources in the LFRM.

Table 2 – Historic Uplift Costs Paid by CT[8]

	CT NCPC Payments		
Month	DAM	RTM	Total
Oct-05*	$33,341	$1,007,900	$1,041,242
Nov-05	$29,236	$3,091,429	$3,120,664
Dec-05	$87,183	$5,581,148	$5,668,330
Q4 2005	$149,760	$9,680,476	$9,830,236
Jan-06	$31,977	$2,420,513	$2,452,490
Feb-06	$70,108	$1,683,953	$1,754,061
Mar-06	$236,192	$1,540,263	$1,776,455
Apr-06	$130,112	$2,786,525	$2,916,637
May-06	$18,236	$3,519,598	$3,537,834
Jun-06	$584,147	$6,377,429	$6,961,576
Jul-06	$322,474	$8,325,663	$8,648,137
Aug-06	$356,016	$5,837,355	$6,193,372
Sep-06	$343,977	$6,856,436	$7,200,413
Oct-06	$166,520	$7,331,100	$7,497,620
Nov-06	$219,198	$6,557,711	$6,776,909
Dec-06	$61,931	$3,580,767	$3,642,698
Total 2006	$2,540,889	$56,817,312	$59,358,201
Jan-07	$28,983	$555,738	$584,721
Feb-07	$21,621	$524,429	$546,050
Mar-07	$178,472	$6,020,129	$6,198,601
Apr-07	$135,515	$3,445,816	$3,581,331
May-07	$223,782	$2,279,962	$2,503,744
Jun-07	$59,290	$2,956,986	$3,016,276
Jul-07	$141,909	$2,891,779	$3,033,688
Aug-07	$136,848	$2,039,888	$2,176,736
Sep-07	$12,217	$2,949,743	$2,961,960
Oct-07	$169,380	$5,169,318	$5,338,698
Nov-07	$98,820	$2,377,365	$2,476,185
Dec-07*	$11,330	$107,092	$118,422
YTD 2007	$1,218,167	$31,318,245	$32,536,412

*partial months

As a starting point, based on the most recently completed 12-month period NCPC data (from December 2006 through November 2007) presented in Table 2, the Department assumes that the current annual NCPC payments amount to approximately $36.06 million. For the purpose of this analysis, the Department assumes that the first 200 MW of the initial 290 MW are procured at $8,500/MW-month, while the remaining 90 MW are procured at a higher price.[9]

8 http://www.iso-ne.com/othrmkts/opsres/tcorc_rpt/ncpc.do

9 In the context of the ISO-NE LICAP case, the Cost of New Entry (CONE) was estimated at $7.50/kW-month based on the frame combustion turbine technology. Here, the Department has increased the CONE to address the higher capital costs and an increased likelihood of aero-derivative technology being more appropriate in providing quick start service. In spite of the long-term contract incentive, the Department does not expect the lowest cost offerings being lower than $8.50/KW-month. The floor cost assumption is based on the most recent LFRM auction results for Winter 2007/2008 in NEMA/Boston. In this recent auction, 395 MW was offered to meet the TMOR requirement of 235 MW in NEMA/Boston, and the market

Without actually knowing what quantities of LFRM will be offered at what price, the Department is compelled to postulate a reasonable supply curve based on previous bid data that has been made public. Naturally, once proposals are submitted to the Department, the actual supply curve can be calibrated. Using reasonable assumptions, the Department has estimated the costs and benefits of each 10 MW increment of new capacity. These data are presented in Attachment 1.

The actual LFRM payments by the Connecticut customers depend not just on the LFRM clearing prices in CT, but also on the LFRM clearing prices in the other New England reserve zones and the price differential between the reserve zones. However, the CT cost allocation factor does not change with the procurement of the initial 290 MW because the LFRM zonal price separation is assumed basically unchanged. In this analysis, the Department assumes that when the amount of capacity offered into the LFRM exactly matches the LFRR, the clearing price will still be set at around $14,000/MW-month.[10] The cost allocation methodology is discussed in more detail in Attachment 3.

The FCM offset is applied to the entire New England gross LFRM generation fleet's revenues in order to calculate the net New England-wide LFRM revenues. The total CT LFRM payments are calculated based on the net New England-wide LFRM revenues and the CT cost allocation factor, as described in Attachment 3. The FCM offset is based on the assumed FCM clearing price and the total capacity that clears in the LFRM. As additional resources are procured in the LFRM up to the LFRR, the total FCM offset therefore increases. The Department estimates that the FCM offset ranges from $233.2 million to $259.3 million. The input data and assumptions for calculating the FCM offset are presented in Attachment 1.

Although they will be dispatched infrequently, the LFRM resources will also provide some energy benefits. The net energy payments received by the resources from the energy markets will be refunded to Connecticut ratepayers. Based on the Department's review of historical data, we do not expect the procured quick start resources will be dispatched with a capacity factor higher than 3%.[11] The input data and assumptions for calculating the net energy benefits are presented in Attachment 1. The net annual energy benefit

cleared at $8.50/kW-month. The Department believes this example is applicable to CT, where like in NEMA/Boston, locational requirements are established and where the LFRM offers may eventually exceed the requirement. Regardless, the Department's analysis shows that this parameter selected within a reasonable range mostly affects the amount of net benefits, and to a lesser degree the optimal amount of quick start capacity. The optimal amount of quick start capacity is more strongly dependent on the shape of the assumed supply curve for existing resources (see Attachment 2).

[10] The Department has reviewed the Offer Curves presented by ISO-NE in the Reserve Markets Report and found that it is quite possible that the LFRM TMOR in CT may clear at around $13,000/MW-month if the offered capacity exceeds the LFRR by approximately 100 MW. The Offer Curves for CT and SWCT are reproduced in Attachment 2.

[11] See ISO-NE Reserve Markets Report at 14-15.

component of the LFRM benefit is estimated to be $3.8 million when the LFRR is fully met.

Under this and other assumptions discussed earlier, the total LFRM annual net benefits to Connecticut ratepayers of the initial 290 MW block of new capacity are estimated at $45.8 million. The reduced NCPC payments contribute $30.8 million to the total benefits, while the reduction of the CT payments to the LFRM resources contributes an additional $15.0 million. The formulae for calculating the components of the net benefits are depicted in Table 1A of Attachment 1.

4. Capacity in Excess of the LFRR

Pursuant to ISO-NE rules, no market value is placed on a reliability increment that may result from exceeding the LFRR. Adequate operational reliability requirements are represented by the LFRR, and ISO-NE will not clear in the LFRM more capacity than the minimum needed to operate the system in a reliable fashion.[12] However, this is not to say that incremental peaking capacity over the requirement is not economically beneficial to Connecticut ratepayers. There are several benefits that can be identified, qualitatively or quantitatively, with regard to the so-called "overhang"[13] capacity:

- it will put some competitive forces into play and mitigate the risk of market power;
- it will further reduce clearing prices in the LFRM;
- it will reduce the CT zone's share of the total New England system-wide costs paid in the LFRM;
- it will displace some of the resources with the priciest offers in the LFRM and shift them into the competitive energy markets, where their participation may potentially reduce the on-peak LMPs; and
- it will add flexibility to the Department and EDCs in steering some portion of the peaking capacity between the markets when economically feasible.

Some of the above benefits can be quantified. A cost/benefit analysis, discussed in the next section, can be used to estimate how much overhang would be beneficial to ratepayers.

[12] The excess of quick start resources that did not clear the LFRM will move into the energy market and will continue to be designated as capacity resources in the Forward Capacity Market (FCM) towards meeting the Installed Capacity Requirement (ICR) and will contribute towards lowering the Loss of Load Expectation (LOLE). In this respect, these resources would support the long-term system planning reliability objectives.

[13] By "overhang" the Department means the amount of quick start capacity that participates in the LFRM auction in excess of the LFRR.

5. Overhang Capacity Need Determination

Procurement of quick start resources beyond the initial block would, in fact, depress the LFRM clearing prices. However, complete or very substantial depression of the LFRM clearing prices may not be beneficial to ratepayers in the long run. Any incremental increase in procured capacity would be beneficial as long as the incremental costs to procure are offset by the incremental benefits based on the LFRM clearing price, otherwise the ratepayers would be paying for contracted capacity above the market price.

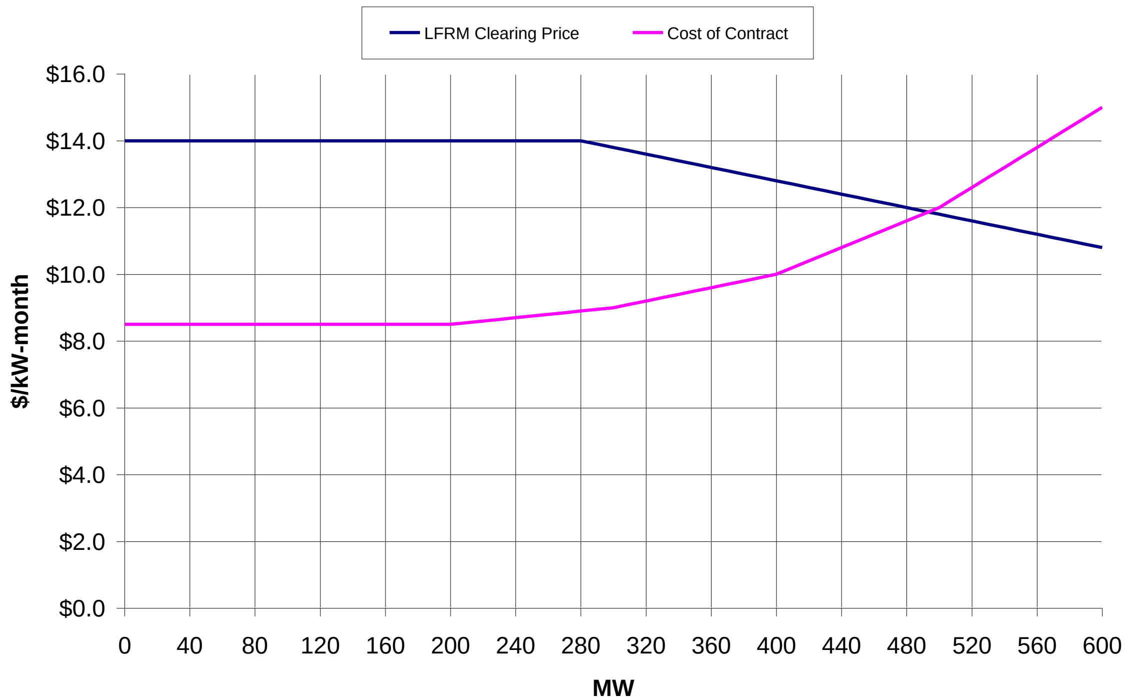
The optimal quantity of "overhang" is a function of the price that is offered for the additional block of capacity. Therefore, it cannot be pre-determined in advance of receiving the pricing proposals. However, the Department can derive a useful estimate of the expected quantity, using available market information and bidder behavior in the prior ISO-NE auctions. On a preliminary basis, the Department developed a simple model to calculate the beneficial overhang block that is based on a set of reasonable assumptions regarding the shape of the offer (supply) curve. The postulated supply curve is not intended to establish threshold prices for new peaking capacity, but simply to illustrate how the benefits analysis would be performed.

The supply curve assumptions are summarized in Table 3, below, and illustrated by the diagram presented in Figure 1, below.

Table 3 – Postulated Correlation between New Capacity, LFRM Prices, and Contract Costs

MW Block	Clearing Price ($/MW-mo)	Cost of Contract ($/MW-mo)
0 – 200	$14,000	$8,500
200 – 280	$14,000	$8,500 - $8,900
280 – 380	$14,000 - $13,000	$8,900 - $9,800
380 – 480	$13,000 - $12,000	$9,800 - $11,600
480 – 600	$12,000 - $10,800	$11,600 - $15,000
600 - 800	$10,800 - $8,800	$15,000

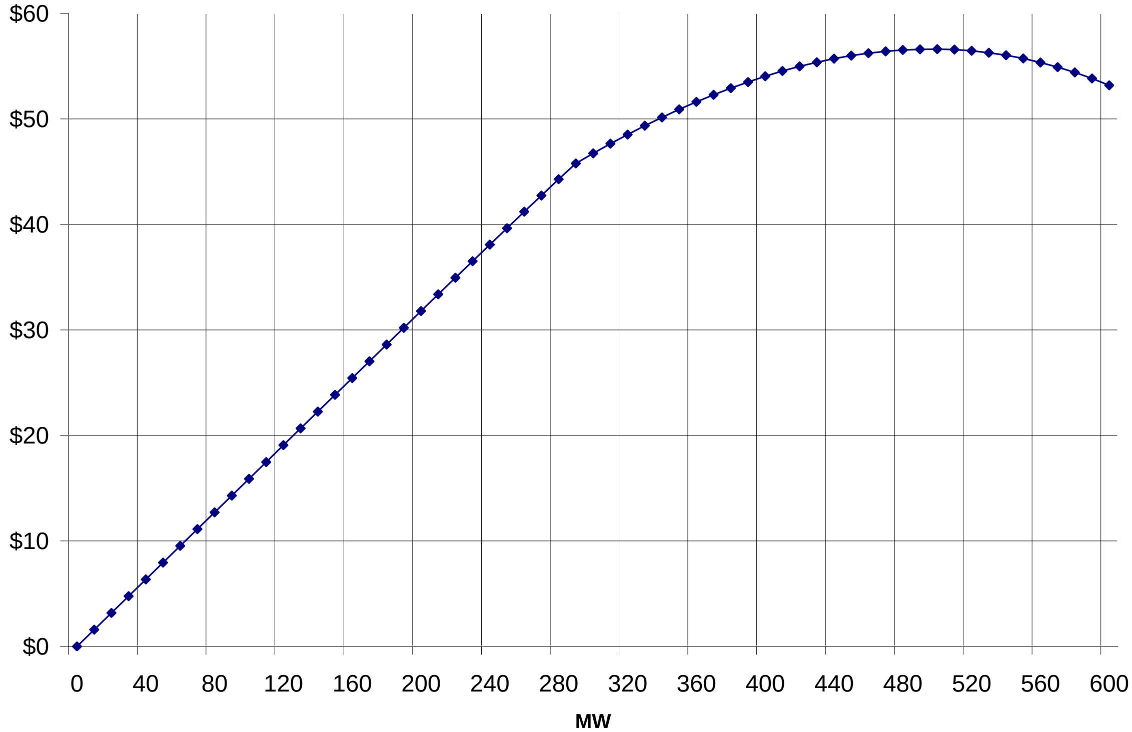
Figure 1 – Effect of New Capacity on LFRM Clearing Prices



The optimal amount of the "overhang" capacity corresponds to the maximum level of the overall net benefits. The total Connecticut benefits are calculated as the sum of the LFRM benefit and the NCPC benefit. The LFRM benefit results from the reduction of the Connecticut share of the LFRM total payments and from the market revenues earned by the procured resources from the LFRM, FCM, and Energy markets. The benefits are offset by the costs the ratepayers pay to the procured LFRM resources. Taking into account the changing allocation factor and comparing the existing CT LFRM costs to the LFRM costs after procurement of the additional quick start resources, the Department has estimated that CT net benefits are maximized when 500 MW of new peaking capacity is procured, i.e., with the "overhang" capacity of 210 MW over the 290 MW needed to meet the LFRR.

The total benefits for Connecticut ratepayers can be roughly estimated at $56.6 million per year (see Attachment 1). This total is comprised of the $30.8 million associated with the reduction of the uplift costs, and the $25.8 million benefit due to the reduction in the LFRM costs. Figure 2 below illustrates how net annual benefits are affected by the amount of additional quick start capacity in CT.

Figure 2 – Connecticut Ratepayers Net Benefits ($MM) vs. Procured LFRM Capacity



Additional capacity procured beyond the 500 MW point does not result in any additional benefits. In fact, the total net benefits start to gradually decline. This effect is attributable to the assumptions that (1) the LFRM clearing price reduction continues at a steady pace; and (2) the incremental cost of contracts increases. It is also questionable whether benefits could be sustainable over the longer term if the clearing price declines below the equilibrium point which is the cost of new capacity.

Of course, the results are only as good as the assumptions. If the offer prices in the overhang block are better than the assumed ones, it might be beneficial to procure some more capacity. However, if the offer prices are above the prices assumed, the size of the overhang should be reduced. The optimal overhang will be a function of actual price proposals in Phase 2 of the procurement process. The model can be refreshed and applied again in Phase 2 of the process when the actual bids become available and the optimal amount of the overhang capacity will be appropriately adjusted. At this time the Department finds that the 500 MW procurement level should be considered a maximum amount of capacity which can be reduced if the results of the first FCM auction are available and indicate that new peaking capacity with LFRM-qualified quick start capability located in CT has cleared the auction.[14]

[14] The Department realizes that the actual offers may not come in discrete 10 MW increments and understands that the best overall portfolio maybe somewhat higher or lower than the

The Department recognizes that efficient peaking generation projects that can lower the LMPs for all Connecticut load during scarcity hours may offer ratepayer energy benefits. Additional energy benefits arise whenever the project's energy revenues exceed the contract energy payments.[15] These energy benefits may offset all or a portion of the additional costs for a more efficient technology. Based on the Department's preliminary analysis, the LMP benefits for a peaking technology that is efficient may be material. Using a dispatch simulation model for a single year, 2011, the Department estimates that 300 MW of efficient peaking generation that bids into the DAM at its marginal cost of production would reduce the market cost of energy to Connecticut load by $2 million to $5 million (less than 1% of the cost to load). However, this is a short term, generic analysis for a single year. The Department recognizes that actual LMP benefits will vary from season-to-season and year-to-year, and depend on units that are not selected for LFRM obligations. The Department also notes that the benefits derived from the difference between the market revenues and the contract energy payments are not included in this simple analysis.

Furthermore, the energy benefits may not be directly derived from the new resources procured. For example, a less efficient new peaking resource that is procured through this initiative may clear in the LFRM auction and displace an existing unit that might otherwise have cleared. The energy benefits would thereby be derived from the displaced existing unit, and depend on the efficiency (heat rate) of that existing resource. A more efficient existing peaker is more likely to be displaced from the LFRM because it would bid its higher opportunity cost. This unit would produce more benefits in the DAM.

B. STANDARD CONTRACT

The Department finds that merchant generators are not public service companies regulated by the Department. The Department has no legal statutory basis to subject an entity that is not a public service company to Department regulation pursuant to Title 16 to cost of service regulation absent an agreement in which a non-public service entity agrees that it will subject itself to the Department's regulation. As such, the Department agrees with participants' views that a contract is necessary to carry out the intent of the Act to permit merchant generators to propose Department-regulated cost-of-service generation projects. The Department, therefore, will require all projects that are not owned and operated by an electric distribution company (EDC), including projects owned and operated by an unregulated affiliate of an EDC, to enter into a contract.

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optimal level of 500 MW due to the size of the last potentially successful resource. A comparative cost/benefit analysis of the two portfolio scenarios, with and without the last potentially successful increment of capacity, will be the basis for the final determination.

[15] As long as the project bids its actual marginal costs, cost-of-service contract energy payments would never exceed the market energy revenues.

The Department approves a modified version of the financial Contract for Differences (CfD) approved in Docket No. 05-07-14PH02, DPUC Investigation of Measures to Reduce Federally Mandated Congestion Charges (Long-Term Measures). See Attachment 9. The Department finds that a CfD is the best type of contract for the purpose of avoiding conflict with FERC jurisdiction over wholesale rate regulation over purchases and sales of electricity, and to avoid any possible negative impacts on the electric distribution companies resulting from accounting or credit rating treatment of contracts. All project sponsors will be required to agree to the terms and conditions of the Department-approved CfD.[16]

The CfD will be between an EDC and the generator (Supplier). In the modified CfD in Attachment 9, the Department conforms the CfD approved in Docket No. 05-07-14PH02 to cost of service principles.

In its Written Exceptions at pages 2 through 9, CL&P raises a variety of objections to entering into contracts with any approved merchant projects. CL&P's chief complaint is that Section 50 does not require use of contracts whereas other procurement statutes expressly mandate use of contracts. Although Section 50 does not expressly mention the use of contracts, it does not expressly exclude the use of contracts either.[17] In terms of implementing the legislative intent of Section 50, the Department does not see how it can carry out the clear legislative intent that non-EDCs, who are not regulated by the Department either as electric distribution companies or public service companies, can offer proposals and, if selected, be regulated by the Department unless there is a contractual arrangement binding the non-EDC project to be regulated by the Department. Without a legally binding contract granting the Department the same type of regulatory authority it has by statute over EDCs and other public service companies, the Department is concerned that a non-EDC project could have a greater likelihood of successfully removing itself from the Department's regulation through collateral attack in other judicial or administrative forums and reducing the Department to the role of litigant in disputes in these other forums versus the Department exercising its legislatively intended role as regulator of the non-EDC project. Also, the Department has broad general authority to order the EDCs to enter contracts with Section 50 merchant peaking generators under Section 16-11 which empowers the Department to order public service companies to take actions as may be reasonably necessary in the public interest. For these reasons, the Department believes that it is in the best interests of

[16] Bidders will be permitted to recommend modifications to the CfD, but are strongly encouraged to refrain from requesting material substantive modifications. Any proposed revisions to the CfD must be submitted in redline to the Department with the project proposal.

[17] Section 50 charges the Department with implementing the very complex undertaking of obtaining new peaking generation. While the statute provides very broad guidelines for the Department to follow, it does not give express directives regarding many issues the Department must address in implementing the statute. The Department will have to use its best judgment, based on its knowledge, expertise and experience, in each instance to determine how best to implement Section 50 to procure cost-of-service peaking generation in a manner that serves the best interest of ratepayers.

ratepayers for there to be a contract with any non-EDC projects selected. All other docket participants who commented on this issue agree with the Department.

As the regulator, the Department cannot be the counterparty to any such contract because it regulates the cost-of-service rate and will serve as the arbiter of any disputes arising out of the contract. The Department would have a conflict of interest.

CL&P also claims that any contract would be void for lack of consideration to CL&P. CL&P receives consideration for performing all of its duties. The EDCs, in exchange for monopoly electric distribution franchises with cost-of-service recovery, are obliged to perform duties for the benefit of their franchise customers such as serving as counterparty to contracts that are necessary to implement Section 50. The EDCs will recover their costs of the contract price and contract administration.

An EDC will not be required to sign a contract for projects wholly-owned and operated by an EDC because the Department will automatically impose cost of service regulation on the EDCs pursuant to its authority under the provisions of Title 16 of the General Statutes of Connecticut which will apply in full to regulation of any EDC projects that are approved. In its Written Exceptions at pages 8 and 9, UI and NRG request that the Department clarify that cost of service regulation under Section 50 can be implemented through Department decisions or contracts or a combination of the two, as necessary. The Department agrees. Non-EDC projects signing CfDs specifically agree by virtue of Section 3.1 of the CfD to be regulated by the Department and bound by its Decisions and orders as well as the Agreement's terms. As noted below, the Department will require any projects wholly owned and operated by the EDC to comply with and be governed by the same requirements contained in the CfD even though they will not be required to sign a contract. The Department will determine whether or not any UI and NRG proposal or proposals require a contract after reviewing the specific details of said proposal or proposals in Docket No. 08-01-01. If UI will be a shareholder in a joint venture with NRG in which NRG operates the peaking generation, the Department will most likely require a contract. If a UI affiliate enters the joint venture with NRG, the contract could be with UI or CL&P. If UI and NRG are in the joint venture, the contract could be with CL&P.

In oral arguments, UI attempted to explain how a contract similar to that used by Seabrook nuclear Power plant and other joint owner nuclear plants in the past would be appropriate and consistent with cost of service principles in this setting. The Department does not look back as favorably on these contracts as UI. These contracts were approved by FERC and sent to the DPUC for recovery thereby severely restricting the Department's authority to examine the underlying cost of service and prudence of expenditures. The Department will not allow this to happen with these generation projects. All contracts between owners or owners and their affiliates will be open for the Department s review to ensure that they are cost-based and reasonable. Any contract that the

Department determines to be unreasonable or imprudent will be subject to disallowance. Similarly, any fees, incentives, or contingencies that are not typical and in line with regulated cost of service practices will not be allowed for recovery.

In its Written Exceptions at pages 3 and 4, Bridgeport Energy II, and Pinpoint Power at page 5, requested clarification that all of the terms and conditions of the CfD will apply to EDCs for projects wholly owned and operated by an EDC even though they will not be required to sign a CfD. As a requirement for approval of EDC projects, through this Decision, the Department will require that EDC projects comply with and be governed by the same general requirements contained in the CfD regarding performance, performance and completion security, liquidated damages and early termination payments.[18] The EDCs will be required to meet the performance standards and obligations contained in Articles 2 and 3 of the CfD. The EDCs will be compensated according to the mechanism contained in Section 6.1 of the CfD. The general rules regarding default and default remedies of Article 8, Force Majeure in Article 9, Credit and Security in Article 10, and Contract Administration in Article 11 will also apply to EDC projects.

In its Written Exceptions at page 18, CL&P seeks clarification regarding the cost allocation between UI and CL&P for collection and payment for the costs of any Department-approved projects. CL&P recommends an 80/20 split with CL&P customers paying 80 percent and UI customers paying 20 percent. The Department agrees with this proposal as the projects will benefit all customers regardless of what franchise area they are located in. The Department further directs CL&P and UI file, as a compliance filing, a red-lined cost sharing agreement based on the ones previously used by the Companies in Docket Nos. 03-07-17RE03 and 05-07-14PH02.

In response to Written Exceptions, the Department revised provisions of the CfD.[19] If a requested revision is not contained in the CfD, the Department rejected it.

In its Written Exceptions, UI requested that the Department form a working group comprised of docket participants for the purpose of reviewing and recommending changes to the CfD. After a very extensive stakeholder process in Docket No. 05-07-14PH02, the Department previously approved a CfD that is substantially similar to this CfD in this docket. The Department has also afforded several opportunities in this proceeding to offer comments on contract terms and conditions, including the opportunity to conduct a working group process.

[18] The Department believes that this is necessary in order to avoid an indirect subsidy to an EDC by virtue of exempting them from certain requirements that have actual or potential costs associated with them that are placed on merchant projects. By way of example, it could constitute a subsidy to an EDC to not require it to maintain performance security when merchant generators are required to procure it.

[19] Revisions were made to the definition of “Qualified Capacity” and Sections 2.1(b), 2.5(g), 2.6(c)3., 2.6(g), 3.1(a), 3.1(b), 3.3.(g), 4.1(b), 4.3(d), 8.1(e), 8.3(a), 10.1(a), 10.2(b), 12.1(a), 12.1(c), 12.1(e), 12.1(f) and 12.11(c).

Additionally, the Department has made a majority of the revisions requested by participants in their Written Exceptions, including those requested by UI and NRG. Finally, project sponsors may request modifications to the CfD for Department review with their project submission. Based on the foregoing, the Department will not conduct a CfD working group process.

C. COST OF SERVICE

The Act applies a fairly standard definition of a cost-of-service based rate providing for recovery of "prudently incurred costs of such project, including, but not limited to, capital costs, operation and maintenance expenses, depreciation, fuel costs, taxes and other governmental charges and a reasonable rate of return on equity." It also calls for an "annual retail generation rate contested case" to review the cost of service and the manner in which winning projects bid into ISO-NE markets.

Cost of service as applied by the Department has varied for particular cost categories and for utilities overall in the past. Cost of service can include both cost trackers and revenue trackers to accommodate operating and market events between rate cases. These trackers accommodate circumstances where history, with test period adjustments, is not a reliable predictor of going-forward costs or revenues for the period during which rates will be in effect. While it may be appropriate to allow the actual recovery of some costs, fully tracking all costs eliminates the incentive for the regulated company to minimize its costs or increase revenues. Another approach with respect to certain costs includes the use of a risk-reward framework. Under traditional cost of service regulation the Department forecasts costs and revenues for the rate year. Actual costs and revenues vary which results in a higher or lower return than allowed in the rate case. This creates a better incentive for the regulated companies to reduce costs and maximize revenues. The Department has also approved other incentive approaches to encourage performance such as earnings sharing, cost recovery dead bands and other sharing mechanisms in the past.

The Department believes that cost of service regulation that creates incentives for generators to control their costs is appropriate in this case, and is consistent with cost of service principles. Use of proper incentives can protect both buyer and seller and promote a healthy response rate to the Section 50 solicitation. Therefore the Department will use a forecasted rate year. All costs will be forecasted at the time of the annual rate case for the upcoming “rate year” subject to the provisions described below. Energy and variable O&M will be trued up to actual costs at the time of the next annual proceeding. The generator will be at risk for fixed O&M and A&G. Market prices may be difficult to predict and are not within the control of generators. Revenues, therefore, will be trued up to actual market prices. Generators will be allowed to keep any over earnings and will be at risk for any under recovery during the rate year.

AARP claims in its Written Exceptions at pages 1 and 2 that the

Department's cost-of-service framework set in the Draft Decision is incentive-based ratemaking and is prohibited by Section 50. The Department disagrees. First, Section 50 directs the Department "***to review*** such recovery of costs [in annual contested case rate proceedings] consistent with the principles of sections 16-19, 16-19b and 16-19e. . . " Section 50 does not limit the Department to only applying those three sections or to prohibit the Department from applying principles from other sections of Title 16 or Department decisions in its development of the cost-of-service framework. Rather, Section 50 authorizes the Department to develop a cost-of-service framework that results in the selection of plans to build peaking generation that are in the best interest of ratepayers and consistent with the principles of section 16-19, 16-19b and 16-19e.

Second, the framework established by the Department in this Decision is a cost-of-service approach consistent with sections 16-19, 16-19b and 16-19e and in the best interests of ratepayers in that Department's framework promotes peaking generators to perform with prudence, economy and efficiency, and establishes just and reasonable maximum rates. The Department seeks to hold project sponsors accountable for delivering services as close as possible to the price represented in their proposals and to limit ratepayer liability for any excessive cost overruns.

Finally, the Department believes that if it adopted AARP's recommendations consumers would be placed at greater risk of rate increases because, without some of the limitations the Department's cost of service framework places on cost recovery, consumers would be giving peaking generators a blank check to fund the entire cost of any cost overruns no matter what the cost. The Department's framework is designed to hold peaking generators to the costs contained in their original proposal as much as possible while ensuring that they can recover costs necessary to provide safe, efficient and adequate service.

1. Capital Costs

Regarding capital costs, the Department will require each project sponsor to complete an Operating Data Sheet similar to the example shown in Attachment 4, and a Capital Cost Estimate sheet similar to the example shown in Attachment 5. It is the Department's belief that a project's capital costs should be readily and accurately determined by the project sponsor at a project's outset. Accordingly, the project's capital cost submission to the Department will be the basis for the evaluation of proposals.

Actual capital expenditures that exceed the estimate by less than 5%, that are determined to be prudent, will be recoverable with the allowed rate of return. Capital expenditures between 5% and 10% greater than the estimated cost at the time of the proposal will be recoverable, if prudent, however, they must withstand a higher level of scrutiny. Any amount above 10% will be presumed imprudent, and, therefore, not recoverable from ratepayers. However, this presumption is subject to rebuttal. Upon commercial operation, if the demonstrated capacity of the project is less than the proposed capacity, the Department will also disallow recovery of capital expenditures that are disproportionate to the actual demonstrated capacity of the project. An illustration of how allowed capital costs would be determined is included in Attachment 7.

If the Facility is constructed such that the resulting Contract Summer Qualified Capacity (CSQC) is less than the capacity originally proposed by the Supplier, the costs will be treated consistent with the methodology described above. For example, assume that a developer proposes a 100 MW facility but upon completion only 90 MW is produced at the same total cost of $100 million. In this case, the project cost has increased from $10/kW to $11.1/kW or 11%.

The Department will share on a 50%/50% basis capital cost savings that are as much as 5% less than the proposed price on a dollar per kW basis. Generators would have to make a showing that they managed the project in a way that resulted in lower costs and/or higher capacity than originally anticipated. Revenue requirements will be fully reduced to reflect any incremental cost reductions if the initial capital costs are more than 5% below the cost estimate contained in the proposal. In such cases, the first 5% reduction will also be shared with customers.

Developers should include their best estimates of the cost and timing of major capital additions in their proposals. Major capital additions should be estimated at the time the project plan is submitted. Major capital additions must be preapproved by the Department during annual rate cases and will be subject to the same considerations as described for the initial capital expenditures at the time of the annual rate cases. Major capital additions arising from unforeseen new legal requirements, market rule changes, or force majeure will be allowable, if prudently incurred.

All efforts should be taken by the project proposers to accurately estimate interconnection costs and minimize the actual cost. The Department, however, recognizes that actual costs may vary significantly from the estimate. Therefore all prudent costs of electrical or natural gas interconnection will be 100% recoverable by the project from ratepayers.

2. Depreciation

Depreciation expense for each project will be determined on a straight-line basis over 30 years for ratemaking purposes (normalization), with any difference between book and tax expense reflected as Accumulated Deferred Income Taxes (ADIT) to be recorded as a rate base item.

3. Operating Costs

Operating costs are generally classified into four areas: Fuel costs; O&M expenses, Administrative and General (A&G) expenses; and Taxes.

The cost of fuel will be considered by the Department to be 100% recoverable by the project from ratepayers, subject to a cap based on the quantity of fuel that would be consumed at 105% of the proposed heat rate, with an allowance for startup fuel. This bandwidth is intended to account for variations in heat rate due to load variations, and is expressed in the formula for the Monthly Variable Revenue Requirement in Exhibit E of the CfD. The Department recognizes that some projects may have fuel plans that do not readily fit into the proposed formula, and therefore would consider alternate mechanisms for recovery of actual fuel costs, provided that the alternative mechanism still holds the project to a comparable efficiency target. The Department will review fuel management and procurement practices at the time of the annual rate case to ensure that costs are prudent, and all reasonable efforts are taken to minimize such costs.

O&M, A&G and Tax expenses are to be enumerated by project sponsors in a manner similar to the example shown in Attachment 6, and in the 30-year project pro forma. Project sponsors may specify that certain fixed and/or variable O&M expenses are a function of a broad-based publicly available index, such as the GDP Implicit Price Deflator or a specific Producer Price Index. Any such indices must be clearly defined in the project pro forma. Aside from fuel expense, all other O&M, A&G and Tax items enumerated in the initial project proposal will be the basis of the allowed revenue requirements in the initial year of project operations. The Department will closely scrutinize the allocation of A&G from a parent company or EDC to the generator, and allow only those costs that are ordinary, necessary and reasonable.

In subsequent years, the Department will allow for recovery of prudently-incurred annual fixed O&M and A&G cost increases up to 2% (in real terms), above the projected budget for fixed O&M and A&G contained in the initial proposal. Similarly, the Department will allow for recovery of prudently incurred costs for variable O&M expenses that are up to 2% above the project budget on a unitized basis (for example, dollars per operating hour or dollars per MWh). There shall be a rebuttable presumption that amounts greater than 2% above the proposed budget, adjusted for the actual value of each of the specified indices will be considered unreasonable and, therefore, not recoverable from ratepayers.

The Department will review tax items separately as they are subject to federal, state and local legislation and mandates, thus not necessarily under the control of the project owners. The Department therefore will allow all appropriate changes to taxes.

4. Cost Recovery

The Act states that “a person operating a peaking generation unit pursuant to this section shall bid the unit into all regional independent system operator markets, including the energy market, capacity market or forward reserve market, using cost-of-service principles and pursuant to guidelines established by the department each year in the annual retail generation rate case pursuant to this section". Further the Act requires that "such peaking generation facility is operated at such times and at such capacity so as to reduce overall electricity rates to customers."

The Act does not require or restrict the generation to either financial arrangements or the physical delivery of products provided the conditions noted above are met. The regulatory paradigm could change over the next few years or certainly over the life of these contracts. Since projects will not come on line for several years it is not necessary to lock in the type of arrangement or markets the units will participate in at this time. The Department will make these determinations for the first year in an appropriate proceeding closer to the initial operation date and thereafter in the annual rate case. Therefore, the Department will not commit to the recovery of generation costs by the EDC's through the NBFMCC charge as requested by CL&P at this time. The Department will determine the appropriate charge when the other issues are decided. In any case, the Department will allow the full recovery of all generation costs incurred by the EDC's as required under these contracts. Likewise all credits will be fully passed through to the benefit of ratepayers.

In their written exceptions, CL&P requested that all costs associated with their peaking proposal be recovered from ratepayers even if their project is not selected since the EDC's are required by the Act to make a proposal. The Department agrees and therefore allows all incremental costs for outside services. The Department will not allow recovery of the costs of deposits and options on land and equipment. In this regard, the Department agrees with the oral argument of Pinpoint that to allow such recovery would provide a competitive advantage to the EDC's and therefore is not appropriate.

The Department will also allow recovery for any incremental administrative costs needed for the LDC's to administer the contracts. The Department will allow the EDC's to recover administrative costs and the costs of their generation proposals in the interim through the NBFMCC charge. Such costs will be allocated to customer classes using a peak demand allocator similar to that approved for other peaking resources recovered through the NBFMCC charge. The Administrative costs will be collected through the same charge as all other costs associated with the projects selected and therefore the appropriate rate component used for recovery and allocation to rate classes may change in the future.

5. Revenues and Performance

The generator must participate in various ISO-NE markets as directed by the Department. Such markets may evolve over the contract period and may, therefore, include new capacity reserves, energy, and ancillary service products not presently defined in the lexicon of services approved by the Federal Energy Regulatory Commission (FERC). Revenues earned in the capacity reserve, energy and ancillary service markets offset the Supplier's revenue requirement.

If the market revenues are not sufficient to cover the Supplier's allowed revenue requirement, the EDC will collect revenue from retail customers under cost of service based rates sufficient to cover the Supplier's revenue requirement. Alternatively, if the Supplier's market-based revenues exceed the Supplier's allowed revenue requirement, the Supplier will credit the net revenue to the EDC solely for the benefit of ratepayers.

The standard contract prescribes the pricing and payment formulae in accord with the CfD transaction structure and cost of service principles. Pricing and payment terms also incorporate a means of adjusting payments to penalize Supplier's underperformance as well as reward Supplier's superior performance relative to benchmarks for capacity. The approach is described below and provided in Sections 2.6(d) and 6.1 of the Standard Contract, Attachment 9. This same mechanism will also apply to any approved EDC project.

The approach defines contract quantities for the market products offered by the Supplier. The contract capacity (termed the Contract Summer Qualified Capacity, or "CSQC") is initially determined based on a seasonal claimed capability test that must be conducted prior to Commercial Operation in accordance with Section 2.6(d) of the Standard Contract. The CSQC is set equal to the initial Summer Seasonal Claimed Capability. The CSQC will then be held constant for the contract term unless changed with the approval of the Department during the annual rate case.

Once commercial operation is achieved, actual quantities and performance may deviate from month to month from the CSQC. The proposed payment mechanism in Section 6.1 of the Standard Contract stipulates that the EDC's payments to the Supplier are equal to the monthly revenue requirement less the market value of the products based on the *contract* quantities and performance specifications. The Supplier retains the *actual* market revenues, therefore the Supplier will be rewarded or penalized for over- or under-performance. Under this pricing and payment mechanism, the Supplier has an incentive to meet or exceed the contract quantities for market products, efficiency, and availability. The pricing and payment mechanism is also intended to accommodate ISO-NE market rules and product definitions.

D. CAPITAL STRUCTURE AND ROE

The Department has the opportunity in this docket to set forth ratemaking treatment that will induce entry to meet both reliability and economic objectives. Regulatory certainty reduces risk and therefore should reduce the investor's required rate of return, thereby providing a benefit to both UI's and CL&P's customers regardless of who is selected to add peaking generation in Connecticut. Some sellers will be interested in leveraging their balance sheet strength in order to win the competition. Other sellers may not have a balance sheet with the requisite strength or may be unwilling or unable to leverage it in order to attempt to gain a competitive advantage. The Department considered inviting sellers to define both capital structure and rate of return. This invitation would be expected to promote maximum economic “scatter” among project proposals, but might create risk of default if the project is too highly leveraged. On the other hand, the Department could impute a ratemaking capital structure subject to a number of benchmark provisions and adjustment factors in order to promote standardization, but this would not comply with the traditional cost of service paradigm.

1. Capital Structure

Although several Participants are proponents of the Department imputing a capital structure of 50% debt, 50% equity to standardize proposals and ease the evaluation process, the Department finds that a project proposal’s capital structure is an integral element of competition between the project proposals. Accordingly, the Department will not impute a standard debt/equity ratio for this solicitation, but establishes a bandwidth for actual debt/equity ratios ranging from 60% to 40% debt to equity or equity to debt. Within this tolerance band, Suppliers may define whatever capital structure they choose. In reviewing what costs are reasonable for purposes of setting the cost of service from time to time, the Department will use the project’s actual debt/equity levels when determining returns and revenue requirements.

With respect to future changes in the debt/equity ratio chosen by the project owners, the Department will consider future proposals to incent any project to lower debt financing costs when capital conditions warrant. All refinancings will be required to be approved by the Department. Projects will recover the actual interest expense, subject to prudency investigation, if the actual costs exceed the costs included in their proposal.

2. ROE

While this was not a contested case, all participants were given notice that the determination of a reasonable return on equity would be examined in this proceeding. Participants were given several opportunities to comment and were free to submit any information they chose to support their recommendations. A number of Participants have made a number of suggestions to the Department about establishing the ROE benchmark for this procurement ranging from the EDCs’ allowed rates, to 32 basis points (PSNH example) above the EDC rate, to 10.88% allowed by FERC for RMR generators in New England, to as much as 200 basis points above the EDCs’ distribution rates. Discussions have also ensued on whether an EDC’s distribution function is less risky than that of a merchant generator.

The Department finds that there is potentially more risk with building and operating generation under the regulation, structure and performance requirements approved herein. However, the Department is not inclined to establish a “bandwidth” of ROE possibilities. The Department favors an ROE that consists of an Index plus an adder. The Index shall be the average of

CL&P's and UI's Department-approved ROEs. Each project sponsor shall propose an initial project ROE, not to exceed 10.75%. The adder, which may be positive or negative, will then be the difference between the sponsor's proposed initial ROE and the actual average of the EDCs' ROEs upon execution of the contract or issuance of the Final Order, and will be fixed going forward. This will take into consideration, for example, the results of the current CL&P rate case results. The Supplier's ROE will be automatically reset in the future based on the results of future EDC rate cases accordingly.

As an example of the workings of the Index and the "adder", if CL&P's and UI's average allowed ROEs was 9.8% (the Index) at the time the project was approved, and the proposer bid a 10.5% ROE in his submission the "adder" going forward would be fixed at a positive .70% differential above the EDCs' Index. Two years later, if the Index drops to 9.6%, the project's allowed ROE would drop to 10.3% (9.6% Index plus the .70% adder). If the Index subsequently increased to 10.25%, the project's allowed ROE would increase to 10.95%. The Department will automatically make the ROE adjustments on a going-forward basis at the time of the annual rate case for any changes in the Index that occurred during the previous year.

Further, the Department has determined that setting a floor on the potential future ROE of 9.75% will reduce risk, and, therefore, should improve the prices proposed by projects to the benefit of customers. As an option, project sponsors may elect to waive the 9.75% floor, provided, however, that the financing plan contains sufficient evidence that the project can be capitalized.

AARP claims in its Written Exceptions at pages 3 and 4 that the Department may not set an ROE in this proceeding but must set the ROE in a contested case proceeding as Section 50 requires that the ROE be set in the initial contested case rate proceeding. The Department believes setting an ROE prior to the Section 50 proceeding is in the best interest of ratepayers. With some level of certainty about the ROE prior to submission of proposals, the Section 50 solicitation is more likely to result in a more robust response by project sponsors at lower prices than would be the case if the ROE for projects remained a complete mystery to be resolved at a later date. If the ROE is not set until after project proposals are submitted and selected, project sponsors will either not submit proposals or would build risk premiums into their proposals that would result in higher cost proposals.

To comply with Section 50, continuing to take into account the Department's analysis in this Decision, the Department will receive further evidence on the issue of the appropriate level of ROE and issue its final rulings on the initial ROE in the future contested case proceeding in Docket No. 08-01-01. The Department, however, believes that ruling of 10.75% as the maximum allowed return on equity at this time is well within the band of reasonableness for generators under the regulatory scheme approved in this proceeding. Therefore very persuasive arguments would be required to alter the rulings set forth above.

The Department, however, reserves its right under cost of service principles to review the adder and make changes if the underlying risk of the EDC or the generators changes relative to each other.

E. CONTESTED CASE

In the contested case proceeding required by Section 50, in Docket No. 08-01-01, DPUC Review of Peaking Generation Projects, proposals will be submitted and then evaluated and selected based on the criteria established in this decision. The Department can reject proposals it determines are not in the best interest of ratepayers, or approve, or approve with modifications, proposals it finds to be in the best interest of ratepayers. The Section 50 project selection process differs from a traditional competitive bid process in that: 1) after receiving the cost-of-service (COS) proposals, the Department may request that any person submitting a plan submit further information it deems to be in the public interest that the Department shall use in evaluating the proposal; and 2) the Department may approve a project with modifications to the original COS proposal. In addition to approving or rejecting proposals in the contested case proceeding, the Department must also find that estimates of costs of approved projects are good faith estimates; approve COS plans for approved projects; approve final contract terms and conditions for any approved merchant projects or projects sponsored by an EDC's affiliates; establish guidelines for the approved project's participation in the ISO-NE markets; and establish the procedures that projects must follow for the future annual contested retail rate cases.

A Prosecutorial (PRO) Unit will be established which will be totally segregated from the Department staff and the Commissioners that will ultimately review and render a decision regarding project selection. PRO will have a critical role in the procurement process, and, therefore, the Department will hire a consultant to assist the Prosecutorial Unit in its duties. PRO will be responsible for the administration of the procurement and the evaluation of projects. PRO shall conduct all of its communications with project sponsors, docket participants and the Department in writing and receive responses to its communications in writing on the record. Except for discussion of procedural matters, PRO shall have no off-the-record communications with any person regarding its work in the contested case proceeding. If PRO needs additional information from any project sponsor, PRO shall direct an interrogatory or interrogatories to the project sponsor. In accordance with the attached proposed schedule (Attachment 8), PRO shall provide the Department its recommendations as to the projects that should be selected along with supporting information and analysis. The Department and all parties and intervenors will have an opportunity to examine the recommendations, submit interrogatories and question the PRO's witnesses at a hearing.

At the conclusion of the contested case, the Department will review the all of the evidence, including the PRO's recommendations as well as evidence presented by other parties and intervenors in the proceeding, and issue a decision approving, approving with modifications, or rejecting the proposals.

F. FILING INSTRUCTIONS AND CONTESTED CASE SCHEDULE

Project sponsors shall submit their proposals in a two-step process. Bidders should file their initial project Qualification Submission described below in Section G, no later than February 1, 2008. The Department will promptly notify bidders if they qualify or not. Qualified Project Sponsors must submit their detailed proposal, as described below in Section H on or before March 3, 2008. Beginning March 3, 2008, the Department will conduct and complete its contested case within one hundred and twenty (120) days. The schedule is attached as Attachment 8.

Bridgeport Energy II objects to the proposed schedule on the basis that it believes that the Department should receive all proposals by February 1, 2008 and then issue a decision within one hundred and twenty days of that date. The Department believes that its schedule complies with both the February 1, 2008 submission date and the one hundred twenty day deadline for issuing a decision. The Department's schedule complies with the Section 50 February 1, 2008 submissions date because the Department will receive the initial Qualification Submissions by project sponsors by that date. The Department will determine who qualifies as Qualified Sponsors. After this initial screening of qualifications, only Qualified Sponsors shall file complete fully-detailed proposals on March 3, 2008. Under the proposed schedule, the Department will issue a decision within one hundred and twenty days of receipt of March 3, 2008; the day complete fully-detailed proposals are filed by Qualified Sponsors.

The schedule Bridgeport Energy II proposes in its Written Exceptions is not in the best interest of ratepayers as it will likely result in the Department receiving fewer proposals because potential project sponsors will have had insufficient time to prepare a proposal in response to the Department's December 14, 2007 Decision in this proceeding. The Department is also concerned with receiving proposals from project sponsors that simply do not possess the minimum technical, managerial and financial capabilities to build peaking generation in a manner consistent with the best interest of ratepayers. Bridgeport Energy II's proposed schedule would also likely result in the Department receiving lower quality or incomplete proposals due to lack of time for sponsors to prepare proposals and this, in turn, would place tremendous time pressure on the Department and other docket participants to conduct discovery and a hearing, analyze proposals and make determinations about what proposals may be in the best interest of ratepayers. More importantly, as indicated in the Needs Assessment above, and as indicated in the Letter in Lieu of Exceptions of ISO New England dated December 10, 2007, the Department will be able to reevaluate the peaking generation need once the FCM Auction results are made public in early March of 2008. The Department will be able to see the quantity of peaking generation clearing in the FCM and make appropriate adjustments to the Needs Assessment that may impact what quantity of new peaking generation is ultimately in the best interests of ratepayers. For the foregoing reasons, the Department intends to follow the schedule outlined in

Attachment 8 and expects all project sponsors who wish to be found to be Qualified Sponsors will follow the Department's filing instructions above.

Project Sponsors must file an appropriate motion for protective order requesting protected treatment for any information that sponsors seek to keep confidential. Project sponsors are directed to use the protective order used in Docket No. 05-07-14PH02 as a template. See, Department letter to participants dated November 27, 2006 in Docket No. 05-07-14PH02. Project sponsors should not file any information they seek to protect electronically. Such information should only be filed in hard copy under seal clearly marked "Confidential - Protected Material" along with the motion requesting protected treatment. If a bidder has any questions regarding filing requirements, it should contact Acting Executive Secretary, Louise Rickard, at (860) 827-2601.

G. QUALIFICATION SUBMISSION – MINIMUM PLAN REQUIREMENTS

In accordance with Section 50, the EDCs and other project sponsors shall submit a plan to build peaking generation. To allow the Department to determine whether or not the proposed projects meets the technical, financial and managerial capabilities necessary to implement the proposed project and whether the project meets minimum threshold criteria, the Department requires that all project sponsors provide, at a minimum, the following information in their proposed plans by February 1, 2008:

1. General Information

a. Project sponsor's name, address, telephone number, and email address.

b. Principal contact person(s) name, title, company, mailing address, telephone number, fax number, email address

c. Legal status of project sponsor, *e.g.*, corporation, partnership, limited liability company, and affiliation, if any to an electric distribution company

d. If project sponsor proposes to have a guarantor guaranty its obligations, the information in items 1-3 above must also be provided with respect to the guarantor. If a consortium or joint venture submits a plan, the plan must clearly set forth the names of each member of the consortium or joint venture and provide complete information for each member of the consortium or joint venture.

2. Experience of Proposed Project Team

a. A description of project sponsor's technical and managerial experience and qualifications in the areas of permitting, development, financing, construction, and operation of electric generating facilities. Include a description of the project sponsor's experience in controlling cost overruns.

b. A description of the project sponsor's familiarity and experience with ISO-NE markets and requirements, and its membership status with ISO-NE. Information indicating all generating plants owned and/or operated by the project sponsor should also be included, including projects currently in construction.

c. Other principal team members, such as EPC contractor and O&M contractor, and the relevant experience of these entities.

d. Disclosure of any instances where the project sponsor, any of its officers, directors or partners, any of its affiliates, or its proposed guarantor (if any) defaulted or was deemed to be in noncompliance with any obligation related to the sale or purchase of power (capacity and/or energy), transmission, or natural gas, or was the subject of a civil proceeding for conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions, or collusive bidding or other procurement- or sale-related irregularities.

e. Disclosure of any instances where the project sponsor, any of its officers, directors or partners, any of its affiliates, or its proposed guarantor (if any) was convicted of (i) any felony, or (ii) any crime related to the sale or purchase of power (capacity and/or energy), transmission, or natural gas, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions, or collusive bidding or other procurement- or sale-related irregularities.

f. Information indicating project sponsor's and any guarantor's financial condition and evidence of creditworthiness. Credit information must include the company credit rating from Standard & Poor's, Moody's, or Fitch, including the last rating date and the senior unsecured long term debt rating. The Project sponsor must provide its and any guarantor's most recent two years' audited financial statements. If audited financial statements are not available, please explain.

3. Project Description

a. The proposed location and description of the site and surroundings. If location is a re-use of an existing generation site, or a remediated brownfield site, please note.

b. Electric interconnection point with the transmission system, status of proposed interconnection application to ISO-NE, cost estimates, and copies of any interconnection studies completed.

c. Technology type, number and size of units, cost estimates, ISO-NE queue position, and configuration. State whether black start capability is to be included, or if such capability could be added at a later date.

d. A demonstration that the project can provide full seasonal rated output in 30 minutes from cold conditions, i.e.,, it will be eligible for at least thirty-minute operating reserve (TMOR) in accordance with ISO-NE rules.

e. An estimated in-service date and milestone schedule.

f. Status of registration in FCM and LFRAM markets.

4. Fuel Supply Plan

a. The proposed primary fuel type and, if applicable secondary fuel.

b. Amount of liquid fuel storage capacity either on-site or contracted for, if applicable, fuel storage replenishment rate and logistics.

c. Natural gas interconnection point(s), source(s) of supply; interstate and local transportation arrangements; imbalance resolution arrangements.

d. Other fuel supply and transportation arrangements, if applicable.

e. A demonstration that, if called upon by ISO-NE to operate at any time, the facility has sufficient fuel fuel on site or through firm resupply arrangements to operate continuously at full load for a minimum of 24 hours.

5. Permitting Plan

a. A list of all federal, state, and local permits, certifications, and approvals required to construct and operate the facility, and a plan for securing such permits.

b. Current status of all required permits, certifications and approvals.

c. Documentation of community support for project.

6. Confidentiality

a. An indication of what information, if any, is proprietary and confidential.

7. Contract

a. Exceptions to the contract, or a statement that the contract is acceptable in its entirety.

H. DETAILED PROPOSAL REQUIREMENTS

Based on the information provided above, the Department will promptly notify project sponsors if they comply with the minimum threshold criteria or not. Qualified sponsors must submit the following information in a detailed technical proposal on or before March 3, 2008.

1. Detailed Project Information

Provide design, operating, and other technical information regarding the project, including the following:

a. Site layout and general arrangement diagram(s)

b. Operating parameters. To facilitate the Department's review, operating data must be provided in Attachment 4. Sponsors may provide additional detail as well.

c. An update to the information provided under Section D.3.b above regarding the electric interconnection application and any interconnection studies completed or underway.

d. An update to permit status

2. Project Schedule

a. A detailed critical path schedule, including timelines for permitting, engineering, procurement, construction, startup, and commercial operation. Include dates for submittal of the FCM Show of Interest and Qualification Package and interconnection requests to ISO-NE. Indicate milestones which have already been achieved.

b. Commercial Operation Date

3. Financing Plan

a. Project sponsors must provide a financing plan for the project, demonstrating that the project can be financed

4. Project Cost

a. Capital costs should be summarized in Attachment 5 and supplemented with detailed cost estimates and expenditure schedules supporting the Proposed Capital Cost, which must include all escalation and Allowance for Funds Used During Construction (AFUDC) or capitalized interest. Best estimates should be provided for electric interconnection and gas interconnection costs.

b. Proposed fixed and variable operating costs should be provided in Attachments 6[20]. Sponsors should indicate the assumed operating levels (annual operating hours, energy output, and unit starts) and indicate how much of each cost category is fixed (independent of operating level), proportional to operating hours, proportional to energy output, or proportional to the number of starts. Costs should be specified in 2008 dollars, and proposed indices (e.g., GDP Implicit Price Deflator or a specific Producer Price Index) should be identified in the Notes space for each cost category.

c. Provide a project pro forma over the term of the Agreement that identifies the project Annual Fixed Revenue Requirement (AFRR) for each year and variable rates for non-fuel operations and maintenance, expressed in terms of dollars per megawatt-hour, dollars per operating hour, and dollars per unit start. The AFRR shall be calculated based on the following:

- A capital structure of between 40% and 60% debt to equity or as much as 60% to 40% debt to equity
- An initial ROE that is indexed to the EDCs' regulated ROE plus a risk adder as described above, but not to exceed10.75%.
- The capital costs and fixed operating costs provided in Attachments 5 and 6.
- If any planned future capital additions are included, they should be clearly described, estimated in 2008 dollars, and escalated to the year of expenditure. Irregular patterns of operating costs

[20] A description of each revenue and expense account to be reported can be found in the Department's Uniform System of Accounts prescribed for Electric Utilities located at http://www.state.ct.us/dpuc - Statutes & Regulations – DPUC Regulations – Sec. 16-27-7 – in the attached Word and Adobe files.

(such as overhauls scheduled on operating hours) should be identified and explained as well.

- If the Consumer Price Index (CPI) or another broad based inflation index is used to determine any price component, assume an annual rate of 2.5% across the entire term.

d. The project sponsor may provide an option for the EDCs to buy out the Facility at the expiration of the contract term. If the project sponsor wishes to offer this option, indicate how the terminal (residual) value of the asset will be treated upon expiration of the contract term, including delineation of site lease restrictions, notification provisions, or other commercial provisions affecting the distribution of benefits upon termination.

e. If black start capability can be added at a later date, provide a cost estimate to do so.

5. Confidentiality

Identify what information in this submittal, if any, is proprietary and confidential.

I. Evaluation Criteria

In accordance with Section 50, the Department must evaluate the peaking project proposals to determine whether the proposed projects are in the best interests of ratepayers. The Department will evaluate all responsive proposals based on qualitative and quantitative evaluation criteria set forth below. After the plans are submitted, the Department may request additional information from sponsors that it deems appropriate for purposes of evaluating proposals and ensuring they are cost based..

1. Minimum Threshold Criteria

In submitting proposals for the Department's evaluation, the electric distribution companies and other project sponsors must demonstrate that the proposed projects meet certain minimum threshold criteria related to the sponsor's managerial, technical and financial capabilities. These minimum threshold criteria are those factors that are either explicitly mandated by Section 50, or are otherwise deemed by the Department to be essential for the project to be in the best interests of ratepayers. These minimum threshold criteria are intended to be straightforward factors that can be assessed by the Department in an initial review of the proposals and do not require extensive financial, commercial, or engineering analysis. Proposed projects that do not comply with each of the minimum threshold requirements will not be considered by the Department for further evaluation.

The minimum threshold criteria are as follows:

1. The proponent possesses sufficient technical, managerial and financial capability to implement the proposal in accordance with the Department's requirements.

2. For proposals submitted by electric distribution companies, the electric distribution company must demonstrate that the project will not be supported by any form of cross subsidization by affiliated entities. This is an explicit requirement of Section 50.

3. The project must meet all eligibility requirements to participate in the ISO-NE LFRM auction to satisfy the CT Reserve Zone requirements upon attaining commercial operation.[21]

4. Plan sponsors must demonstrate a legal entitlement to each site on which a project is proposed to be built. Proof can be in the form of current ownership of the property, a current lease on the property, or an option to lease or buy the property that can be exercised at any time until the Department issues its final decision on the proposal and a contract is executed. Project sponsors must also demonstrate a legal entitlement to any required right of way to access electrical and fuel interconnection points.

5. Project sponsors must demonstrate that, if called upon by ISO-NE to operate at any time, the facility has sufficient fuel fuel on site or through firm resupply arrangements to operate continuously at full load for a minimum of 24 hours.

6. As specified in Section 50, the sponsors must provide plans for building new generation projects. Existing generating capacity does not conform with this requirement. However, plans that propose capacity uprates to existing generation facilities or new units to be constructed at existing facilities do meet the minimum threshold requirement, but only for the incremental capacity offered. If the project is an uprate to an existing facility, the plan must clearly specify how the products from the new incremental capacity will be distinguished from those from the existing capacity

[21] Section 50 requires plans to build "peaking generation," which is generally defined as generating capacity intended to meet peak demand. Peaking generators can operate in the capacity and energy markets as well as provide ancillary services, principally forward reserves. While the Department recognizes that new peaking generation may provide benefits through all three product types, projects that can provide locational forward reserves fulfill the most immediate need and offer the most potential benefits to ratepayers in the near term. Projects that are eligible to participate in the LFRM market provide optionality in the sense that they can meet an immediate need for locational forward reserves but can subsequently be directed to other markets, if higher value to ratepayers can be achieved.

7. Project sponsors, or guarantor, must demonstrate a minimum of investment grade credit rating, as defined in the attached contract. Comparable alternative credit support, such as Letter of Credit from a qualified institution as defined in the attached contract, may be provided.

8. Project sponsors must agree to adhere to the CfD without substantial material modifications. The Department will determine whether any proposed contract modifications are "substantial material" modifications.

2. Costs and Benefits to Ratepayers

Each proposed project will be evaluated with respect to the project's costs and benefits to Connecticut ratepayers. This will be a multi-step process. In the initial due diligence, capital and operating costs will be evaluated to determine if they are reasonable and complete, based on industry benchmarks for similar projects. PRO and the Department can request clarification from project sponsors regarding costs and technical aspects of the proposals. Based on such clarifications, PRO may recommend, and the Department may require, adjustments to such costs and recalculation of the AFRR if certain items or contingencies have not been included in the proposals. In particular, PRO sill independently estimate costs for electric interconnection and gas interconnection, and may adjust the project sponsor's estimate if there is a material difference. Once these adjustments to the AFRR are made, the Department will gauge the projects using this adjusted AFRR value. All projects will be rank ordered by converting the AFRR to a dollar per kilowatt-month basis. Projects of similar technology type will be grouped together. Within a similar technology type, projects that have a significantly higher dollar per kilowatt month cost may be excluded from the analysis, unless the project offers an exceptional qualitative feature that merits further consideration or unless the project's exclusion results in the total selected capacity being below the target quantity calculated as described in Section III.

Next, using the methodology described in Section III, the needs assessment will be updated to refine the target quantity. A reassessment of the existing peaking generation in Connecticut likely to participate in the LFRM, will be used to recalculate the initial block of capacity to be procured to meet the LFRR. Projects will be selected, starting with the lowest priced projects available, until the LFRR is met by this initial block. The benefits of each additional project in the initial block are derived from the reduction of uplift, and the difference between Connecticut's share of the pool LFRM costs and the project cost. Since the benefits are similar for each project, and linear for the first 290 MW, projects will be selected based on their cost on a $/kW basis.

For the “overhang” block, the benefits are derived by reducing the LFRM clearing price, up to the point beyond where no incremental benefits are realized. Energy benefits will also result by adding more capacity than is needed to clear the LFRM market. Peaking units not selected to meet the LFRM requirement will participate, or force other units to participate, in the energy market, thereby reducing energy rates.

Although the Department has estimated that the “overhang” block to be 210 MW based on reasonable assumptions regarding the supply curve, the actual “overhang” quantity will be determined based on prices of the proposed projects. The incremental net benefit of each additional project will be determined based on the amount to which we assume that the new project lowers the product of the LFRM clearing price and Connecticut’s percentage share of the pool LFRM cost, less the project cost. Projects will continue to be selected until the point where the next project does not yield any further incremental benefits above its costs.

At this point, the selection process does not yet consider energy benefits. As a next step, PRO will assess and provide its opinion in its recommendations to the Department regarding whether the projects yield appreciable LMP benefits. The Department recognizes that at any time, a generator is unlikely to both clear in the LFRM market and be dispatched in the DAM or real time energy market more than a very few hours per year; nonetheless, the energy benefit analysis is performed under the assumption that all resources under consideration fully participate in the energy market.

Using dispatch simulation modeling for a set of sample years, PRO will determine the extent to which each project lowers the hourly LMPs, relative to the dispatch of the system without the project. The gross annual energy benefit of the project will be calculated as the sum of the LMP differentials in each hour multiplied by the hourly Connecticut load. The annual contract variable cost of the project is then deducted from the gross energy benefits to derive the net energy benefits of the project. This calculation captures both the benefits of the project derived from potentially reducing state-wide clearing prices in the DAM or real time energy market, and the fact that load is only paying for the project’s energy at its marginal cost.

PRO will then compare the net energy benefits of the projects that are not yet selected to the projects that previously “cleared.” to meet the LFRR and the “overhang” block. Projects offering superior energy benefits may replace previously cleared projects. First, PRO will calculate an energy-adjusted price for each project by subtracting the net energy benefits (expressed in $/kW-year) from the proposed fixed price (i.e., AFRR, also expressed in $/kW-year). As a next step, PRO will sort the projects by this new measure, and select those projects with the lowest adjusted prices until the cumulative capacity roughly equals the quantity established in the need analysis. PRO will include the afore-described energy benefits analysis and findings in its recommendations to the Department regarding project selection.

3. Qualitative Factors

Each proposal that meets the Threshold Criteria will also be subject to a qualitative evaluation based upon an overall assessment of its merits. If the Department determines that there is not a substantial difference (e.g. +/- 5% expressed in $/kW) in the costs to ratepayers of two or more proposals, the Department will give proposals containing the following attributes (not necessarily listed in an order of importance) more favorable consideration in making its determination of which projects are in the best interest of ratepayers:

1. Early Commercial Operation Date and low risk of project delays, certainty of achieving key project development milestones, including securing permits and interconnection agreements;
2. Low risk of cost increases to ratepayers resulting from factors such as electric transmission and fuel interconnection costs, PILOT, and technical attributes of project; cost of equipment and materials;
3. Project sponsor's and development team's managerial, technical and financial capability in developing and operating generation projects;
4. Environmental benefits, including net reduction in emissions of air pollutants and greenhouse gases and reuse of existing generation or brownfield sites;
5. Blackstart capability;
6. TMNSR capability;
7. Opportunity to purchase Facility at expiration of the contract at beneficial terms;
8. Furtherance of fuel diversity; and
9. Location in SWCT.

PRO will apply these criteria to proposed projects and include its analysis of these criteria in its recommendations to the Department.

IV. FINDINGS OF FACT

1. For several years, Connecticut has had a shortage of several hundred MWs of peaking generation needed for reliability to satisfy compliance with the LFRM requirements.

2. Connecticut consumers have paid and will continue to pay a $14/kw/m penalty in the LFRM instead of a potentially much lower market clearing price as result this peaking generation shortfall.

3. Taking into account new peaking generation in operation or under contract for the future Connecticut, Connecticut needs at least 290 additional MWs to meet the LFRM requirements.

V. CONCLUSION AND ORDER

A. CONCLUSION

In this Decision, the Department: 1) provides the contested case schedule; 2) determines, subject to further review in February 2008, that there is a peaking generation need of five hundred (500) megawatts of new peaking generation; 3) establishes criteria regarding cost of service, capital structure and ROE; 4) identifies the criteria the Department will use to evaluate the proposals; and 5) describes the information that must be provided in the proposals for them to be deemed complete. Additionally, the Department provides a standard contract to be used by merchant generator projects selected and approved by the Department.

B. ORDER

1. CL&P and UI shall file a cost sharing agreement as described in Section III.B above on or before January 15, 2008.

Attachment 1

Table A1 – Calculation of Costs and Benefits of Incremental Quick Start Capacity

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
		Existing MW		LFRM Costs ($MM)															
New MW	Price $/kW-mo	Winter	Summer	Winter	Summer	LFRM Total $MM	NCPC $MM	Cost of Contract $/kW-mo	Cost of Service $MM	Net Energy rent $MM	Refund to CT $MM	CT Allocation Factor	Gross LFRM Payment $MM	NCPC Benefit $MM	FCM Offset	LFRM Net Payment $MM	CT share LFRM $MM	LFRM Benefit $MM	Total CT Benefit $MM
				(A+C)*B*8	(A+D)*B*4	E+F			Σ(A*I*12)		A*B*12+K		N$1+(Gi+1-Gi)	H$1-H		N-P	M*Q	(R$1-R)+L-J	O+S
0	$14.0	1084	839	121.4	47.0	168.4	36.06	8.5	0.0	$0.0	0.0	0.3786	300.6	0.000	$233.2	$67.4	$25.5	0.0	$0.00
10	$14.0	1084	839	122.5	47.5	170.1	34.97	8.5	1.0	$0.1	1.8	0.3786	302.3	1.093	$234.1	$68.2	$25.8	0.5	$1.59
20	$14.0	1084	839	123.6	48.1	171.8	33.88	8.5	2.0	$0.3	3.6	0.3786	304.0	2.185	$235.0	$69.0	$26.1	1.0	$3.18
30	$14.0	1084	839	124.8	48.7	173.4	32.78	8.5	3.1	$0.4	5.4	0.3786	305.6	3.278	$235.9	$69.8	$26.4	1.5	$4.77
40	$14.0	1084	839	125.9	49.2	175.1	31.69	8.5	4.1	$0.5	7.2	0.3786	307.3	4.371	$236.8	$70.6	$26.7	2.0	$6.36
50	$14.0	1084	839	127.0	49.8	176.8	30.60	8.5	5.1	$0.7	9.1	0.3786	309.0	5.464	$237.7	$71.3	$27.0	2.5	$7.94
60	$14.0	1084	839	128.1	50.3	178.5	29.50	8.5	6.1	$0.8	10.9	0.3786	310.7	6.556	$238.6	$72.1	$27.3	3.0	$9.53
70	$14.0	1084	839	129.2	50.9	180.2	28.41	8.5	7.1	$0.9	12.7	0.3786	312.4	7.649	$239.5	$72.9	$27.6	3.5	$11.12
80	$14.0	1084	839	130.4	51.5	181.8	27.32	8.5	8.2	$1.1	14.5	0.3786	314.0	8.742	$240.4	$73.7	$27.9	4.0	$12.71
90	$14.0	1084	839	131.5	52.0	183.5	26.23	8.5	9.2	$1.2	16.3	0.3786	315.7	9.835	$241.3	$74.5	$28.2	4.5	$14.30
100	$14.0	1084	839	132.6	52.6	185.2	25.13	8.5	10.2	$1.3	18.1	0.3786	317.4	10.927	$242.2	$75.2	$28.5	5.0	$15.89
110	$14.0	1084	839	133.7	53.1	186.9	24.04	8.5	11.2	$1.4	19.9	0.3786	319.1	12.020	$243.1	$76.0	$28.8	5.5	$17.48
120	$14.0	1084	839	134.8	53.7	188.6	22.95	8.5	12.2	$1.6	21.7	0.3786	320.8	13.113	$244.0	$76.8	$29.1	6.0	$19.07
130	$14.0	1084	839	136.0	54.3	190.2	21.85	8.5	13.3	$1.7	23.5	0.3786	322.4	14.206	$244.9	$77.6	$29.4	6.4	$20.66
140	$14.0	1084	839	137.1	54.8	191.9	20.76	8.5	14.3	$1.8	25.4	0.3786	324.1	15.298	$245.8	$78.4	$29.7	6.9	$22.24
150	$14.0	1084	839	138.2	55.4	193.6	19.67	8.5	15.3	$2.0	27.2	0.3786	325.8	16.391	$246.7	$79.1	$30.0	7.4	$23.83
160	$14.0	1084	839	139.3	55.9	195.3	18.58	8.5	16.3	$2.1	29.0	0.3786	327.5	17.484	$247.6	$79.9	$30.3	7.9	$25.42
170	$14.0	1084	839	140.4	56.5	197.0	17.48	8.5	17.3	$2.2	30.8	0.3786	329.2	18.577	$248.5	$80.7	$30.6	8.4	$27.01
180	$14.0	1084	839	141.6	57.1	198.6	16.39	8.5	18.4	$2.4	32.6	0.3786	330.8	19.669	$249.4	$81.5	$30.8	8.9	$28.60
190	$14.0	1084	839	142.7	57.6	200.3	15.30	8.5	19.4	$2.5	34.4	0.3786	332.5	20.762	$250.3	$82.3	$31.1	9.4	$30.19
200	$14.0	1084	839	143.8	58.2	202.0	14.21	8.5	20.4	$2.6	36.2	0.3786	334.2	21.855	$251.2	$83.0	$31.4	9.9	$31.78
210	$14.0	1084	839	144.9	58.7	203.7	13.11	8.6	21.4	$2.8	38.0	0.3786	335.9	22.948	$252.1	$83.8	$31.7	10.4	$33.36
220	$14.0	1084	839	146.0	59.3	205.4	12.02	8.6	22.5	$2.9	39.9	0.3786	337.6	24.040	$253.0	$84.6	$32.0	10.9	$34.94
230	$14.0	1084	839	147.2	59.9	207.0	10.93	8.7	23.5	$3.0	41.7	0.3786	339.2	25.133	$253.9	$85.4	$32.3	11.4	$36.51
240	$14.0	1084	839	148.3	60.4	208.7	9.83	8.7	24.5	$3.2	43.5	0.3786	340.9	26.226	$254.8	$86.2	$32.6	11.8	$38.07
250	$14.0	1084	839	149.4	61.0	210.4	8.74	8.8	25.6	$3.3	45.3	0.3786	342.6	27.319	$255.7	$86.9	$32.9	12.3	$39.63

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
		Existing MW		LFRM Costs ($MM)															
New MW	Price $/kW-mo	Winter	Summer	Winter	Summer	LFRM Total $MM	NCPC $MM	Cost of Contract $/kW-mo	Cost of Service $MM	Net Energy rent $MM	Refund to CT $MM	CT Allocation Factor	Gross LFRM Payment $MM	NCPC Benefit $MM	FCM Offset	LFRM Net Payment $MM	CT share LFRM $MM	LFRM Benefit $MM	Total CT Benefit $MM
				(A+C)*B*8	(A+D)*B*4	E+F			Σ(A*I*12)		A*B*12+K		N$1+(Gi+1-Gi)	H$1-H		N-P	M*Q	(R$1-R)+L-J	O+S
260	$14.0	1084	839	150.5	61.5	212.1	7.65	8.8	26.6	$3.4	47.1	0.3786	344.3	28.411	$256.6	$87.7	$33.2	12.8	$41.18
270	$14.0	1084	839	151.6	62.1	213.8	6.56	8.9	27.7	$3.5	48.9	0.3786	346.0	29.504	$257.5	$88.5	$33.5	13.2	$42.73
280	$14.0	1084	839	152.8	62.7	215.4	5.46	8.9	28.8	$3.7	50.7	0.3786	347.6	30.597	$258.4	$89.3	$33.8	13.7	$44.27
290	$13.9	1076	831	151.9	62.3	214.2	5.30	9.0	29.9	$3.8	52.2	0.3769	346.4	30.761	$259.3	$87.2	$32.9	15.0	$45.77
300	$13.8	1066	821	150.8	61.9	212.7	5.30	9.0	30.9	$3.8	53.5	0.3752	344.9	30.761	$259.3	$85.6	$32.1	16.0	$46.72
310	$13.7	1056	811	149.7	61.4	211.1	5.30	9.1	32.0	$3.8	54.8	0.3735	343.4	30.761	$259.3	$84.1	$31.4	16.9	$47.64
320	$13.6	1046	801	148.6	61.0	209.6	5.30	9.2	33.1	$3.8	56.0	0.3718	341.8	30.761	$259.3	$82.6	$30.7	17.7	$48.51
330	$13.5	1036	791	147.5	60.5	208.1	5.30	9.3	34.2	$3.8	57.3	0.3701	340.3	30.761	$259.3	$81.0	$30.0	18.6	$49.34
340	$13.4	1026	781	146.4	60.1	206.5	5.30	9.4	35.4	$3.8	58.5	0.3683	338.7	30.761	$259.3	$79.5	$29.3	19.4	$50.13
350	$13.3	1016	771	145.3	59.6	205.0	5.30	9.5	36.5	$3.8	59.7	0.3666	337.2	30.761	$259.3	$77.9	$28.6	20.1	$50.89
360	$13.2	1006	761	144.2	59.2	203.4	5.30	9.6	37.7	$3.8	60.8	0.3648	335.6	30.761	$259.3	$76.4	$27.9	20.8	$51.60
370	$13.1	996	751	143.2	58.7	201.9	5.30	9.7	38.8	$3.8	62.0	0.3631	334.1	30.761	$259.3	$74.8	$27.2	21.5	$52.27
380	$13.0	986	741	142.1	58.3	200.4	5.30	9.8	40.0	$3.8	63.1	0.3613	332.6	30.761	$259.3	$73.3	$26.5	22.1	$52.90
390	$12.9	976	731	141.0	57.8	198.8	5.30	9.9	41.2	$3.8	64.2	0.3595	331.0	30.761	$259.3	$71.8	$25.8	22.7	$53.48
400	$12.8	966	721	139.9	57.4	197.3	5.30	10.0	42.4	$3.8	65.3	0.3577	329.5	30.761	$259.3	$70.2	$25.1	23.3	$54.03
410	$12.7	956	711	138.8	56.9	195.7	5.30	10.2	43.6	$3.8	66.3	0.3559	327.9	30.761	$259.3	$68.7	$24.4	23.8	$54.53
420	$12.6	946	701	137.7	56.5	194.2	5.30	10.4	44.9	$3.8	67.3	0.3541	326.4	30.761	$259.3	$67.1	$23.8	24.2	$54.97
430	$12.5	936	691	136.6	56.1	192.7	5.30	10.6	46.1	$3.8	68.3	0.3523	324.9	30.761	$259.3	$65.6	$23.1	24.6	$55.36
440	$12.4	926	681	135.5	55.6	191.1	5.30	10.8	47.4	$3.8	69.3	0.3505	323.3	30.761	$259.3	$64.1	$22.4	24.9	$55.69
450	$12.3	916	671	134.4	55.2	189.6	5.30	11.0	48.8	$3.8	70.2	0.3486	321.8	30.761	$259.3	$62.5	$21.8	25.2	$55.98
460	$12.2	906	661	133.3	54.7	188.0	5.30	11.2	50.1	$3.8	71.2	0.3468	320.2	30.761	$259.3	$61.0	$21.1	25.4	$56.21
470	$12.1	896	651	132.2	54.3	186.5	5.30	11.4	51.5	$3.8	72.1	0.3449	318.7	30.761	$259.3	$59.4	$20.5	25.6	$56.38
480	$12.0	886	641	131.1	53.8	184.9	5.30	11.6	52.9	$3.8	72.9	0.343	317.2	30.761	$259.3	$57.9	$19.9	25.7	$56.51
490	$11.9	876	631	130.0	53.4	183.4	5.30	11.8	54.3	$3.8	73.8	0.3412	315.6	30.761	$259.3	$56.4	$19.2	25.8	$56.58
500	$11.8	866	621	129.0	52.9	181.9	5.30	12.0	55.7	$3.8	74.6	0.3393	314.1	30.761	$259.3	$54.8	$18.6	25.8	$56.60
510	$11.7	856	611	127.9	52.5	180.3	5.30	12.3	57.2	$3.8	75.4	0.3374	312.5	30.761	$259.3	$53.3	$18.0	25.8	$56.55
520	$11.6	846	601	126.8	52.0	178.8	5.30	12.6	58.7	$3.8	76.2	0.3354	311.0	30.761	$259.3	$51.7	$17.4	25.7	$56.44
530	$11.5	836	591	125.7	51.6	177.2	5.30	12.9	60.2	$3.8	77.0	0.3335	309.4	30.761	$259.3	$50.2	$16.7	25.5	$56.26
540	$11.4	826	581	124.6	51.1	175.7	5.30	13.2	61.8	$3.8	77.7	0.3316	307.9	30.761	$259.3	$48.6	$16.1	25.3	$56.01
550	$11.3	816	571	123.5	50.7	174.2	5.30	13.5	63.5	$3.8	78.4	0.3296	306.4	30.761	$259.3	$47.1	$15.5	24.9	$55.71

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
		Existing MW		LFRM Costs ($MM)															
New MW	Price $/kW-mo	Winter	Summer	Winter	Summer	LFRM Total $MM	NCPC $MM	Cost of Contract $/kW-mo	Cost of Service $MM	Net Energy rent $MM	Refund to CT $MM	CT Allocation Factor	Gross LFRM Payment $MM	NCPC Benefit $MM	FCM Offset	LFRM Net Payment $MM	CT share LFRM $MM	LFRM Benefit $MM	Total CT Benefit $MM
				(A+C)*B*8	(A+D)*B*4	E+F			Σ(A*I*12)		A*B*12+K		N$1+(Gi+1-Gi)	H$1-H		N-P	M*Q	(R$1-R)+L-J	O+S
560	$11.2	806	561	122.4	50.2	172.6	5.30	13.8	65.1	$3.8	79.1	0.3277	304.8	30.761	$259.3	$45.6	$14.9	24.6	$55.33
570	$11.1	796	551	121.3	49.8	171.1	5.30	14.1	66.8	$3.8	79.7	0.3257	303.3	30.761	$259.3	$44.0	$14.3	24.1	$54.89
580	$11.0	786	541	120.2	49.3	169.5	5.30	14.4	68.5	$3.8	80.4	0.3237	301.7	30.761	$259.3	$42.5	$13.8	23.6	$54.38
590	$10.9	776	531	119.1	48.9	168.0	5.30	14.7	70.3	$3.8	81.0	0.3217	300.2	30.761	$259.3	$40.9	$13.2	23.1	$53.81
600	$10.8	766	521	118.0	48.4	166.4	5.30	15.0	72.1	$3.8	81.6	0.3197	298.7	30.761	$259.3	$39.4	$12.6	22.4	$53.18
610	$10.7	756	511	116.9	48.0	164.9	5.30	15.0	73.9	$3.8	82.1	0.3177	297.1	30.761	$259.3	$37.9	$12.0	21.7	$52.51
620	$10.6	746	501	115.8	47.5	163.4	5.30	15.0	75.7	$3.8	82.7	0.3157	295.6	30.761	$259.3	$36.3	$11.5	21.1	$51.81
630	$10.5	736	491	114.7	47.1	161.8	5.30	15.0	77.5	$3.8	83.2	0.3136	294.0	30.761	$259.3	$34.8	$10.9	20.3	$51.09
640	$10.4	726	481	113.7	46.6	160.3	5.30	15.0	79.3	$3.8	83.7	0.3115	292.5	30.761	$259.3	$33.2	$10.4	19.6	$50.33
650	$10.3	716	471	112.6	46.2	158.7	5.30	15.0	81.1	$3.8	84.2	0.3095	291.0	30.761	$259.3	$31.7	$9.8	18.8	$49.54
660	$10.2	706	461	111.5	45.7	157.2	5.30	15.0	82.9	$3.8	84.6	0.3074	289.4	30.761	$259.3	$30.2	$9.3	18.0	$48.73
670	$10.1	696	451	110.4	45.3	155.7	5.30	15.0	84.7	$3.8	85.0	0.3053	287.9	30.761	$259.3	$28.6	$8.7	17.1	$47.88
680	$10.0	686	441	109.3	44.8	154.1	5.30	15.0	86.5	$3.8	85.4	0.3032	286.3	30.761	$259.3	$27.1	$8.2	16.2	$47.00
690	$9.9	676	431	108.2	44.4	152.6	5.30	15.0	88.3	$3.8	85.8	0.3011	284.8	30.761	$259.3	$25.5	$7.7	15.3	$46.10
700	$9.8	666	421	107.1	43.9	151.0	5.30	15.0	90.1	$3.8	86.1	0.2989	283.2	30.761	$259.3	$24.0	$7.2	14.4	$45.16
710	$9.7	656	411	106.0	43.5	149.5	5.30	15.0	91.9	$3.8	86.5	0.2968	281.7	30.761	$259.3	$22.4	$6.7	13.4	$44.19
720	$9.6	646	401	104.9	43.0	148.0	5.30	15.0	93.7	$3.8	86.8	0.2946	280.2	30.761	$259.3	$20.9	$6.2	12.4	$43.20
730	$9.5	636	391	103.8	42.6	146.4	5.30	15.0	95.5	$3.8	87.0	0.2925	278.6	30.761	$259.3	$19.4	$5.7	11.4	$42.17
740	$9.4	626	381	102.7	42.1	144.9	5.30	15.0	97.3	$3.8	87.3	0.2903	277.1	30.761	$259.3	$17.8	$5.2	10.4	$41.11
750	$9.3	616	371	101.6	41.7	143.3	5.30	15.0	99.1	$3.8	87.5	0.2881	275.5	30.761	$259.3	$16.3	$4.7	9.3	$40.02
760	$9.2	606	361	100.5	41.3	141.8	5.30	15.0	100.9	$3.8	87.7	0.2859	274.0	30.761	$259.3	$14.7	$4.2	8.1	$38.90
770	$9.1	596	351	99.4	40.8	140.2	5.30	15.0	102.7	$3.8	87.9	0.2837	272.5	30.761	$259.3	$13.2	$3.7	7.0	$37.75
780	$9.0	586	341	98.4	40.4	138.7	5.30	15.0	104.5	$3.8	88.1	0.2814	270.9	30.761	$259.3	$11.7	$3.3	5.8	$36.57
790	$8.9	576	331	97.3	39.9	137.2	5.30	15.0	106.3	$3.8	88.2	0.2792	269.4	30.761	$259.3	$10.1	$2.8	4.6	$35.36
800	$8.8	566	321	96.2	39.5	135.6	5.30	15.0	108.1	$3.8	88.3	0.2769	267.8	30.761	$259.3	$8.6	$2.4	3.4	$34.12

Notes:

a. The LFRR is established probabilistically by ISO-NE, based on historical reserve activation data and a 95% probability that the LFRR quantity is sufficient to meet demand. Therefore, even if there are sufficient quick start resources to meet the LFRR in a reserve zone, ISO-NE may still need to call on out-of-merit order generation and the reserve zone would incur NCPC charges a small number of hours each year. The Department has estimated the expected residual NCPC payments (Column 'H') for Connecticut, assuming the LFRR is fully met. Currently, with only 70% of the LFRR satisfied by quick start resources, Connecticut's NCPC costs are $36.06 million. At the 95% level, the residual costs are extrapolated to be $5.3 million, i.e., $36.06 million * (1-0.95)/(1-0.70*0.95).

b. Since the Cost of New Entry (CONE) in the FCM is considered a long term equilibrium point where the FCM will most likely clear, the Department assumes that the FCM average clearing price will be equal to the initial CONE, i.e., $7.50/kW-month. Accordingly, it has estimated the initial FCM offset (Column 'P') at $233.2 million per year: (2,777 MW * 8 months + 2,218 MW * 4 months) * $7,500/MW-month = $233.2 million. The FCM offset reaches $259.3 million at the LFRR: ((2,777 + 290) * 8 + (2,218 + 290) * 4) * $7,500 = $259.3 million.

c. The current gross LFRM payments (Column 'N') equal to $300.6 million are based on the ISO-NE Reserve Market Report that includes the Summer 2007 and Winter 2007/2008 LFRM payments totaling $279.2 million. Assuming that additional 134 MW (winter) and 114 MW (summer) capacity will be part of the existing LFRM resources in the 2011/2012 procurement period, the gross LFRM payments will be calculated as $279.2 million + (134 MW * 8 month + 114 MW * 4 month) * $14,000/MW-month = $300.6 million.

d. The net energy benefit (Column 'K') is estimated under the assumption that the average LMP for the 3% of hours that LFRM resources dispatch is equal to $150/MWh, and the variable costs (fuel) are $100/MWh. The Department believes that the energy cost/revenue assumptions are consistent with the historical data presented by ISO-NE in its 2006 Annual Markets Report. Accordingly, the energy benefit of the initial 290 MW is equal to 290 * 0.03 * 8760 * (150 – 100) = $3.8 million.

Attachment 2

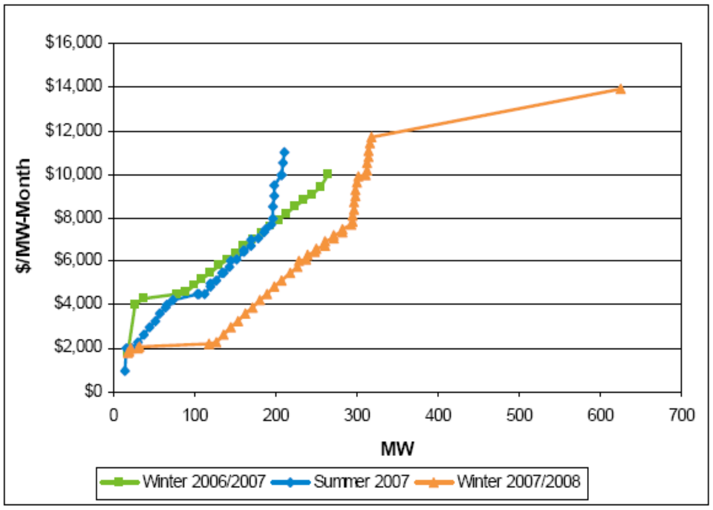

Figure 3-4: CT TMOR Offer Curves, Winter 2006/2007, Summer 2007, and Winter 2007/2008 Forward Reserve Auctions

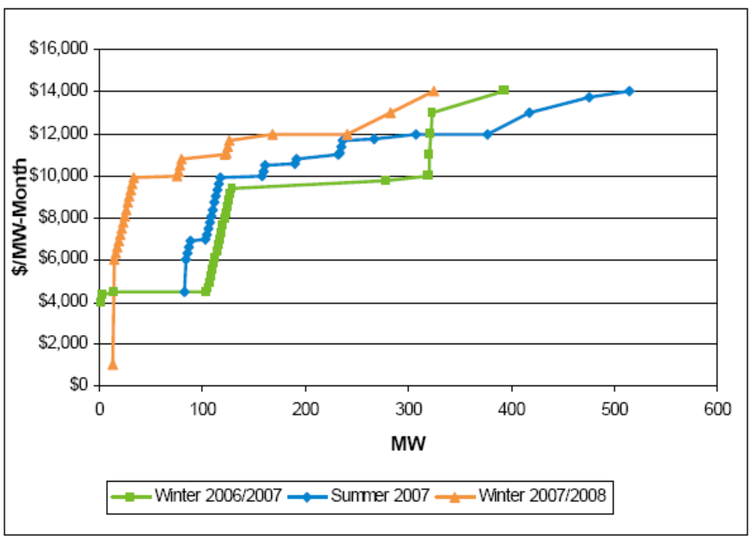

Figure 3-3: SWCT TMOR Offer Curves, Winter 2006/2007, Summer 2007, and Winter 2007/2008 Forward Reserve Auctions

Source: ISO-NE Reserve Markets Report, LFRM Compliance Filing with FERC docket ER06-613-004 dated October 1, 2007

Attachment 3

LFRM Cost Allocation

According to ISO-NE market rules, the net regional LFRM costs are allocated in proportion to the zonal real-time load obligation adjusted by weights that reflect the magnitude of the price separation among the reserve zones. The price separation is a measure of the relative impact of the LFRR on the price. That is, the greater the local constraints, the greater the price separation and the lesser the local constraints the lesser the price separation.

The LFRM cost allocation methodology increases the magnitude of the benefits associated with the reduction of the LFRM clearing price. Indeed, not only would the payment by Connecticut customers decline due to the lower clearing prices per se, but also CT's share of the overall LFRM costs will likely decline once zonal price separation is reduced. Because the Department cannot know today with any certainty nor control the LFRM clearing prices in the zones outside of Connecticut, the analysis above assumed that, eventually, there would be no price separation between CT, NEMA/Boston, and ROS. However, for illustration purposes, the Department provides a few examples that show the potential effect of the LFRM clearing price reduction on the CT share of the LFRM costs under various scenarios.

Case I

In this case, the Department assumes there is no price separation between the reserve zones and all zones clear at $8,500/MW-month. Table A3.1 below shows that Connecticut load's share of costs would be equal to 27% under this scenario.

Table A3.1 – Reserve Zone LFRM Cost Allocation Factors (no price separation)

	Zone	Real Time Load Share	Price ($/MW-month)	Price Ratio	Load Share*Price Ratio	Cost Allocation
CASE I	NEMA/Boston	19.2%	$ 8,500	1.000	0.19	19.20%
	SWCT	12.8%	$ 8,500	1.000	0.13	12.80%
	CT	27.0%	$ 8,500	1.000	0.27	27.00%
	ROS	53.8%	$ 8,500	1.000	0.54	53.80%

Case II

If the assumption is that there is price separation between the zones, NEMA clears at the price cap of $14,000/MW-month while all other zones including CT clear at $8,500/MW-hour. In this case, Table A3.2 below shows that Connecticut load's share of costs under this scenario would be 24%, while NEMA would pay 28% of the total.

Table A3.2– Reserve Zone LFRM Cost Allocation Factors (NEMA at price cap)

	Zone	Real Time Load Share	Price ($/MW-month)	Price Ratio	Load Share*Price Ratio	Cost Allocation
CASE II	NEMA/Boston	19.2%	$ 14,000	1.647	0.32	28.13%
	SWCT	12.8%	$ 8,500	1.000	0.13	11.39%
	CT	27.0%	$ 8,500	1.000	0.27	24.02%
	ROS	53.8%	$ 8,500	1.000	0.54	47.85%

Case III

In this case the assumption is that there is price separation between the zones: CT clears at the price cap of $14,000/MW-month while all other zones including NEMA clear at $8,500/MW-month.[22] According to the results shown in Table A3.3, below, under this scenario, Connecticut load would pay almost 38% of the total net LFRM costs.

Table A3.3 – Reserve Zone LFRM Cost Allocation Factors (CT and SWCT at price cap)

	Zone	Real Time Load Share	Price ($/MW-month)	Price Ratio	Load Share*Price Ratio	Cost Allocation
CASE III	NEMA/Boston	19.2%	$ 8,500	1.000	0.19	16.34%
	SWCT	12.8%	$ 14,000	1.647	0.21	17.95%
	CT	27.0%	$ 14,000	1.647	0.44	37.86%
	ROS	53.8%	$ 8,500	1.000	0.54	45.80%

These results support a conclusion that analysis of the incremental benefits of the overhang capacity beyond the LFRR should be adjusted to reflect the reduction of the CT share of the total costs. For example, if an additional 100 MW drives the clearing price in CT from the cap (such as under Case III) to the equilibrium level (such as under Case I), the CT share goes down from 38% to 27%. If NEMA does not have enough resources (*e.g.*, in summer) the CT benefits would increase even more because CT's share would decline even more (see Case II).[23]

[22] Case III is very similar to the actual results of the last LFRM auction for Winter 2007/2008.

[23] The NEMA/Boston LFRM TMOR results suggest that introduction of the NSTAR 345 kV Phase II transmission line in 2009 will result in adequacy of the existing quick start resources around the year.

Attachment 7

DETERMINATION OF ALLOWED CAPITAL COST

A proposed mechanism for determining the initial capital cost to be allowed in the calculation of Annual Fixed Revenue Requirement is defined below. The mechanism is based on a cost of service approach, subject to caps on return and recovery on a dollar per kW basis.

Capacity Measures:

OFCQ = Original FCM Contract Quantity, MW

This capacity is established in the Supplier's original proposal.

CSQC = Contract Summer Qualified Capacity, MW

This capacity is established during acceptance testing prior to Commercial Operation Date. (If a test of summer capacity is not possible, a non-summer test may be used with appropriate adjustments, subject to later true-up)

Capital Cost Measures:

PCC = Proposed Capital Cost, $

This is the total capital cost defined in the Supplier's original proposal, including all owner's costs, escalation, Allowance for Funds Used During Construction (AFUDC) ,etc.

TACC = Total Actual Capital Cost, $

This is the actual total capital requirement at the Commercial Operation Date, <u>excluding AFUDC accrued after the Proposed Commercial Operation Date</u>.

Allowed Capital Cost Calculations

PUCC = Proposed Unit Capital Cost, $/kW

= PCC / OFCQ

AUCC = Actual Unit Capital Cost, $/kW

= TACC / CSQC

UCCDP = Unit Capital Cost Deemed Prudent, $/kW

= A function of AUCC and PUCC:

a. AUCC if AUCC is equal to 100% of PUCC

b. PUCC plus that portion of AUCC in excess of PUCC that is deemed prudent by Department review. Any cost over 105% of PUCC is subject to a high level of scrutiny, and any amount over 110% of PUCC is presumed imprudent, subject to rebuttal.

c. AUCC plus one half of the difference between PUCC and AUCC if AUCC is less than 100% of PUCC but equal to or greater than 95% of PUCC and Sponsor justifies to Department that the lower costs are attributable to Sponsor's management actions.

d. AUCC plus up to 2.5% of PUCC if AUCC is less than 95% of PUCC and Department determines that the Sponsor's management actions contributed to the cost reduction.

CAF = Cost Allowance Factor

= UCCDP / AUCC

ACC = Allowed Capital Cost, $

= CSQC * UCCDP

= TACC * CAF

Recovery and return are allowed on the full cost determined to be prudently incurred.

Attachment 8

Time Schedule for Contested Proceeding

TIME SCHEDULE

DOCKET NO. 08-01-01

TITLE: **DPUC Review of Peaking Generation Projects**

Panel Assigned:	**CPF**	**HO/LA:**	**Robert Luysterborghs**
Coordinator:	**Debra Morrell**	**Lead Staff:**	**Michael Zawrotny**

Date: **November 27, 2007**

EVENT	DATE
Qualification Submissions Due	2/1/08
Proposal Applications & Pre-Filed Testimony Due	3/3/08
1st Set of Interrogatories Sent	3/11/08
1st Set of Interrogatories Responses Due	3/25/08
OCC/Prosecutorial Pre-Filed Testimony Due	4/1/08
2nd Set of Interrogatories Sent (OCC/Prosecutorial)	4/9/08
2nd Set of Interrogatory Responses Due (OCC/PRO)	4/22/08
Hearing	4/29/08 @ 9:30 a.m.
Hearing	4/30/08 @ 10:30 a.m.
Hearing	5/1/08 @ 9:30 a.m.
Late Filed Exhibits Due	5/9/08
LFE Hearing	5/15/08 @ 9:30 a.m.
Briefs Due	5/22/08
Distribution of Draft Decision	6/6/08
Written Exceptions Due	6/13/08
Oral Arguments (*TENTATIVE*)	6/17/08 @ 9:30 a.m.
Regular Meeting/Final Decision	6/18/08 @ 9:30 a.m.
Deadline (120-days from Application Due Date 3/3/08)	7/1/08

DOCKET NO. 07-08-24 DPUC INVESTIGATION OF THE PROCESS AND CRITERIA FOR USE IN IMPLEMENTING SECTION 50 OF PUBLIC ACT 07-242 - PEAKING GENERATION

This Decision is adopted by the following Commissioners:

Donald W. Downes

Anne C. George

John W. Betkoski, III

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

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

December 14, 2007
Date

Ontario Power Generation Inc. ("OPG")
Interrogatories for GEC

INTERROGATORY #4

Ref: Page 11, lines 16 - 18

Preamble:
"Q. Are you endorsing Ms. McShane's estimate of nuclear risks."
"A. No. I believe that she may be understating the risk of nuclear investment by assuming that consumers would cover parts of the risks."

Interrogatory

You have indicated at page 9, line 15 that some of OPG's proposals transfer risks to ratepayers. If these same risks are also reflected in the cost of capital OPG is allowed to recover in its approved payment amounts, are ratepayers not essentially going to be paying twice for these risks?

Response

As discussed in response to OPG's IR #2, I am suggesting that OPG retain and track the additional revenues to reduce net charges to ratepayers when those risks materialize.

Ontario Power Generation Inc. ("OPG")
Interrogatories for GEC

INTERROGATORY #5

Ref: Pages 10 - 12

Preamble: Mr. Chernick comments on the reasonableness of Ms. McShane's cost of capital estimates, but makes no independent estimates of his own, stating that experts have be retained by other parties to do so.

Interrogatory

Would Mr. Chernick please provide his assessment of the reasonableness of the recommendations of each of the experts retained by Pollution Probe, Energy Probe and VECC/CCC?

Response

Mr. Chernick was not retained to, and has not reviewed those recommendations.

Ontario Power Generation Inc. ("OPG")
Interrogatories for GEC

INTERROGATORY #6

Ref: Pages 13, lines 2 - 8

Preamble:

Q. "Why is it useful to distinguish the costs of capital for nuclear and hydro investments?"

A. "[I]f the OEB establishes separate costs of capital and the mix of OPG's investment changes, due to nuclear retrofits or refurbishment or new nuclear or hydro capacity, OPG's average allowed return would automatically shift in the direction of the investment mix."

Interrogatory

a) Is it Mr. Chernick's assumption that the cost of capital would not change for the separate operating segments as the result of new investment?

b) If new investment was expected to reduce risk, should the operating segment cost of capital be changed to reflect that expected risk reduction? If not, why not?

c) Payments are established based on allowed returns. How would changes in the mix of OPG's generation investments impact customers? What is the practical usefulness of automatic shifts in average allowed returns?

Response

a) I recognize that adding a new investment might change the average cost of capital for the relevant operating segment.

b) The operating segment cost of capital should be reviewed and revised in each rate proceeding, just as cost of capital is currently reviewed and revised in each rate proceeding.

c) Assuming that allowed cost of capital should be set to reflect cost of capital, having cost of capital automatically follow OPG's mix of investment (one of the drivers of cost of capital) should simplify ratemaking. If nothing else changes between rate proceedings, the Board could leave the return for each class unchanged from the earlier proceeding, and the average cost of capital would change with the change in rate base composition.

Ontario Power Generation Inc. ("OPG")
Interrogatories for GEC

INTERROGATORY #7

Ref: Pages 15, lines 4 - 11

Preamble:
Q. "Can "building risk into cash flows" substitute for risk-adjusted cost of capital?
A. "In principle, revenues from a potential investment could be reduced and operating costs increased to reflect the risks. In practice, it is difficult to capture the many risks of a complex business segment in this fashion. Some risks result from small probabilities of large increases in cost components that are expected to be small, while other risks reflect smooth distributions around the best estimate of cost."

Interrogatory

Is there any reason to believe that adjustment to revenues and operating costs for a specific investment determined through techniques such as Monte Carlo simulations, combined with forecast costs of capital for OPG's regulated operations as a whole, will not yield more accurate investment analyses and decisions than using a technology-specific costs of capital?

Response

The Monte Carlo simulations would apparently require many assumptions for each project, including low-probability, high-consequence events. It is not clear how the question suggests these inputs would be estimated, how the simulated results would be incorporated in the analysis, how the analysis would be insulated from the advocates for a given project, or how the OEB or OPG Boards would review these complex studies. There is no reason to believe that the method proposed in the question would produce useful or meaningful results.

Ontario Power Generation Inc. ("OPG")
Interrogatories for GEC

INTERROGATORY #8

Interrogatory

Would Mr. Chernick please identify all articles, publications and reports he has written on the cost of utility capital? Please provide copies of all documents.

Response

I have periodically testified on the cost of utility capital in conjunction with other ratemaking and planning issues, such as an input to computation of avoided costs. I do not believe that the cost of utility capital *per se* has been the principal issue in any of my testimony. If OPG wishes to identify specific items in my resume, I would be happy to provide them.

I am not testifying in this proceeding as an expert at setting utility cost of capital levels. My expertise is in the broader regulatory and investment concepts and the recommendations in my evidence address those matters. I have used the estimates of OPG's own expert to demonstrate that there are real differences in the risks to capital employed in OPGs two divisions, and to guide the Board in utilizing OPG's evidence in setting separate cost of capital by division.

Ontario Power Generation Inc. (“OPG”)
Interrogatories for GEC

INTERROGATORY #9

Interrogatory

Would Mr. Chernick please provide a table showing:

a) The recommended returns on equity and capital structure in each case in which he has appeared since 2000

b) The date of the testimony

c) The client on whose behalf the testimony was prepared

d) The regulatory jurisdiction

e) The date of the decision

f) The awarded returns on equity and capital structures; if the case resulted in a settlement, please so indicate.

Please indicate in which of these proceeding Mr. Chernick was accepted as an expert in utility cost of capital. Please provide copies of all testimonies and accompanying schedules for each of the proceedings listed in the table.

Response

a) Mr. Chernick does not maintain such a tabulation. OPG can determine the cost of capital in the cases in which Mr. Chernick has testified (as listed in his qualifications) from public sources.

b) See Mr. Chernick’s qualifications.

c) See Mr. Chernick’s qualifications.

d) See Mr. Chernick’s qualifications.

e) Mr. Chernick does not maintain such a tabulation. OPG can determine the date of the decision from public sources.

f) Mr. Chernick does not maintain such a tabulation.

See Response to Interrogatory #8 regarding Mr. Chernick's testimony related to utility cost of capital.