Recommendations on Selection of Projects in the 2006 Connecticut RFP Process

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1 Executive summary

In light of rising electricity prices due to an increase in global fuel prices as well as structural changes to the wholesale electricity market in New England[1], the Connecticut legislature passed the Energy Independence Act (EIA)[2] in January 2005, which authorized the Department of Public Utility Control (DPUC) to launch a procurement process to acquire new capacity. The objective of the procurement process was to decrease total costs of electricity consumption for Connecticut ratepayers over the next 15 years[3], including those costs caused primarily by congestion costs, and to improve the reliability of the electricity system in Connecticut.

In February 2006, the DPUC retained London Economics International LLC (LEI) to support it in its efforts to design and launch the procurement process authorized by the EIA.[4] LEI's role includes all aspects in this process from analyzing supply-demand conditions to developing the investment needs analysis to designing the RFP process and the associated contracts to serving as the coordinator for the procurement process. Finally, LEI has also been responsible for analyzing the Financial Bid submissions and making a recommendation regarding winning bidders to the DPUC.

After several months of stakeholder consultation on issues related to RFP design, contract structure, bid evaluation, and investment needs, the DPUC launched an all-source Request for Proposals (RFP) on September 15, 2006. The RFP targeted a broad group of market participants by soliciting proposals for both new generating capacity as well as projects that reduce electric demand. Two standardized contracts were designed for generation and demand side projects that contained similar performance and security requirements but varied with respect to several contract terms in order to accommodate the different technological characteristics of generation and demand-side projects. Both the generation and demand-side contracts utilized a Contract for Differences (CFD) structure, where the pricing for the contract is settled against market prices in specific wholesale product markets run by the Independent System Operator of New

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1 In March 2004, the Independent System Operator of New England (ISO-NE) filed its proposal for a Locational Installed Capacity Market (LICAP) with FERC. It was anticipated that the implementation of LICAP could cost Connecticut ratepayers anywhere between $6.5 and $14.5 billion based on estimates issued by the Connecticut Energy Advisory Board and the Connecticut Attorney General, respectively. However, facing significant opposition from certain stakeholders, ISO-NE changed its plans for a capacity market and in March 2006 submitted its proposal for a Forward Capacity Market (FCM) to FERC, which has since been approved.

2 General Statutes of Connecticut § 16-243m

3 Section 12(i) of the EIA specifically refers to long term contracts, with terms of up to 15 years.

4 The DPUC engaged LEI as a consultant to provide independent detailed economic support to the DPUC in analyzing the bids received as part of the Connecticut 2006 RFP process and in recommending the portfolio of winning bidders. The economic analysis detailed in this report is based on market data and information about market rules and conditions as of December 13, 2006, the date of Financial Bid Submission and consistent with the market information that bidders had access to in developing their Financial Bids. The results provided or opinions put forth in this analysis do not constitute a promise or guarantee as to the occurrence of any future events.

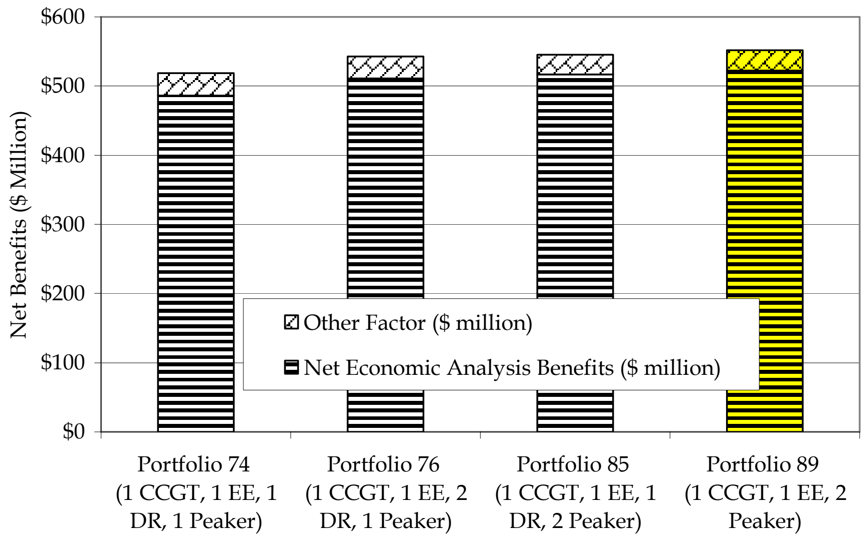
England (ISO-NE). The RFP process was organized to attract a diverse set of proposals and to encourage competition between demand-side and generation-side resources in order to obtain the lowest cost proposals possible. The bid evaluation acknowledged the all-source character of the RFP and was purposely designed to enable LEI to evaluate proposals from different technologies on an equal footing. The bid evaluation process focused on analyzing the likely benefits that each project offered based on its ability to reduce total costs to Connecticut ratepayers net of the annual payments the project requires as proposed in its Financial Bid. The bid evaluation therefore directly captures the EIA's main objective, to minimize congestion costs while also improving reliability at the lowest reasonable cost to ratepayers.

The DPUC received more than 20 Financial Bids from 15 different bidders on December 13, 2006. The relative abundance of proposals, the diversity of the bidders, and the overall range of Financial Bids, leads us to conclude that the RFP was competitive. LEI, as RFP Coordinator, received all Financial Bids. In order to keep each bidder's identity confidential, LEI coded all submissions with random three-digit project identification codes. This report uses these project identification numbers in order to maintain the confidentiality of the identity of the non-selected bidders and their projects. Moreover, in writing this report, LEI has expressly maintained the confidentiality of information submitted by the bidders as part of the RFP process, while also striving to communicate as much information as possible so as to allow stakeholders to more fully understand the analytical process that led to the quantification of net benefits and resulted in the bid selection recommendations.

The bid evaluation process was designed to analyze all aspects of the bids, including the proposed project(s)' economic benefits, their anticipated execution risk, their interconnection risk, their risk of not qualifying for ISO-NE's new capacity market, how the bids performed vis-à-vis other state policy priorities, and what the implications were for market power concerns in the wholesale energy market, should one or more projects be selected as a winning bidder. The Financial Bids were assessed to ensure that they were conforming and each bidder's qualifications were carefully analyzed. Then the Financial Bids were classified by their technology category (baseload generation plants, peaking generation plants, demand response projects, and energy efficiency projects) and evaluated in order to eliminate projects, whose bids were extremely uneconomic as compared to other similar projects. LEI then analyzed each of the remaining individual projects, calculating each project's ability to decrease costs to Connecticut ratepayers in the energy, capacity, and reserves markets and the resulting net benefits for Connecticut ratepayers. Top performing projects were then combined into more than 30 portfolios to assess if combinations of projects resulted in greater net benefits for Connecticut ratepayers, and, if so, which combination of projects resulted in the largest net benefits to Connecticut ratepayers. Other analyses, such as an assessment of each project's and portfolio's ability to improve reliability in the state and each project's and portfolio's performance on a set of state policy priorities, were also incorporated in the final bid evaluation results.

After three months of extensive analysis, LEI has determined that Portfolio 89, consisting of four individual projects, provides the largest net benefit to Connecticut ratepayers as compared to other qualified Financial Bids (and portfolios thereof). (Portfolio 89 is shown in the graphic below as the highlighted bar on the right hand side.) LEI therefore recommends that the DPUC select the projects in Portfolio 89 as winners of this RFP. The winning portfolio constitutes a total maximum capacity of 787 MW and consists of one 620 MW new highly efficient combined cycle gas-fired baseload plant in Middletown offered by Kleen Energy (Project 409), a 66 MW peaking plant located in the constrained Southwest Connecticut region (Stamford) offered by Waterside Power (Project 851), one 96 MW new and highly efficient peaking unit also located in Southwest Connecticut (Waterbury) offered by Waterbury Generation LLC (Project 993), and one state-wide 5 MW energy efficiency program offered by Ameresco (Project 358).

Figure 1. Comparison of top performing portfolios based on weighted average of nine scenarios ($ million)[5]



Note: Net benefits are equal to Gross Benefits minus contract costs. These net benefits are a weighted average of the net benefits estimated across the nine market scenarios studied. Furthermore, these net benefits do not include the energy savings due to demand reduction in the energy market.

On a weighted average basis across the nine scenarios analyzed as compared to our baseline analysis (without any of the selected projects), Portfolio 89 is expected to provide Connecticut ratepayers with $522 million in net economic benefits in 2007 terms because of its impact on wholesale costs of power, namely decreasing Locational Marginal Prices (LMPs) in the energy market, decreasing capacity clearing prices in the capacity market (also known as the Forward Capacity Market or FCM), and decreasing auction clearing prices in the Locational Forward Reserve Market (LFRM).[6] This means that after factoring in the costs of the contracts for all four

5 More detail on these portfolios and all portfolios and projects analyzed is available in the appendix at the end of this report.

6 These estimates do not factor in the value of energy savings (referred to herein as the "quantity impact") that the energy efficiency project could have on the portfolio, which is explained further in Section 4.3. With the quantity impact of Project 358 incorporated, Portfolio 89 is forecast to produce weighted average net benefits of $535 million or $812/kW. See Figure 18 on page 49 for a graphic illustration of the quantity impact.

projects that the portfolio's aggregate impact on the New England wholesale electricity market is still likely to reduce wholesale costs for Connecticut ratepayers by more than half a billion dollars over the modeling time horizon (2007 – 2025), discounted back to 2007 terms. This portfolio is forecast to have the largest net benefit for Connecticut ratepayers of any portfolio or individual project that LEI analyzed in dollar million terms, as shown in the graphic above.

Across the nine market scenarios, Portfolio 89 is projected to create net economic benefits for Connecticut ratepayers that range from $-79 to $1,770 million over the multi-year modeling time horizon. The range in net benefits is based on the results of nine different market scenarios, with differing supply-demand conditions, environmental regulations, and fuel prices. Moreover, Portfolio 89 also received 9.5 points out of a possible 15 points for Other Factors, indicating that it meets many of Connecticut's policy objectives as well, including improving system reliability (which was assessed by PTI Siemens, a transmission system expert). The projects in Portfolio 89 scored high in their technical assessment according to technical review and project risk analysis performed by Inland Energy Consulting. All four projects received low to moderate project execution risk scores, indicating that these projects are likely to be developed as planned within the anticipated timeframe. All of the selected generation projects were considered to have minimal risk in terms of transmission according to analysis performed by PTI Siemens: Project 409 already possesses a completed System Impact Study, indicating ISO-NE approval for interconnection, and Project 851 already has an Interconnection Agreement, which just needs to be converted to permanent status. Project 993 is in the interconnection queue and there are not many projects ahead of it that would directly impact its ability to interconnect. Furthermore, under the reasonable assumptions utilized all three generation projects pass PTI Siemen's independent replication of the Overlapping Impacts analysis that will be part of the ISO-NE Forward Capacity Market qualification process.

LEI also conducted an analysis testing the ability of Portfolio 89 to improve system reliability by preventing blackouts (electricity supply interruptions) due to system stress conditions, similar to those observed historically in New England. In our simulations for a week involving the peak period in 2011 (under the ISO-NE's 90/10 demand forecast), the presence of additional capacity related to Portfolio 89 reduced the duration of potential electricity supply interruptions by nine hours. At a conservative estimate, the cost savings for the local economy for reducing the duration of or averting such interruptions can range from $1,000 to $3,000 per MW of load per hour. Given Connecticut's winter peak load and the nine hours noted above, Portfolio 89 could create savings of $76 to $229 million in the event of a severe gas supply shortage.

Portfolio 89 performed better than any other portfolio or project in terms of forecast economic benefits, allowing us to conclude that it maximized total benefits to ratepayers. In addition, the individual projects comprising the portfolio were the best performing individual projects within their technological category when comparing all proposals on a stand-alone basis. The selected portfolio thus contains the projects that represented the greatest "bang for their buck," thereby maximizing value for Connecticut ratepayers. Moreover, there are numerous risk-minimizing benefits to selecting a portfolio of several projects with different developers and technologies, including reducing risk that the entire amount of capacity will not come online on time and contributing to Connecticut's fuel diversity. The selection of this portfolio also introduces new market participants to the CT electricity sector, expanding the realm of competition. The overall concentration in the New England and Connecticut market actually decreases as a result of the award of the contracts under this RFP to these projects as compared to the status quo. Furthermore, an analysis of strategic bidding potential in the wholesale energy market revealed that this portfolio of projects with their underlying long term contracts actually reduces the potential for higher prices as result of market power abuses. This is not surprising given that the long term contracts reduce incentives for market manipulation and the new capacity frustrates the potential for strategic bidding by other market participants.

Portfolio 89 thus clearly meets the selection criteria of Section 12(i) of the EIA:

- **Portfolio 89 increases system reliability:** Based on a detailed analysis of transmission system conditions, PTI Siemens (an independent engineering firm that specializes in analyzing transmission system conditions) determined that the winning portfolio increases system reliability. It augments the amount of overall generating capacity in the state, reinforcing system-wide transmission security and providing for more permanent fast start resources. Portfolio 89 also introduces new resources that have dual fuel capability and reduces overall electric consumption and demand.
- **Portfolio 89 minimizes congestion costs:** Projects were assessed on their abilities to impact Federally Mandated Congestion Costs (FMCCs) for Connecticut ratepayers going forward. Thus, the winning portfolio demonstrated its ability to reduce FMCCs more than other portfolios or projects after factoring in the payments that will have to be made for acquiring the portfolio. This portfolio of projects has the largest price impact on key ISO-NE markets taking into account contract costs and therefore contributes the most towards reducing congestion costs.
- **Portfolio 89 was procured at the lowest reasonable cost possible:** The RFP was structured and managed in such a way as to maximize competition. The number and variety of Financial Bids received, the mix of technologies, and the consistency of these bids in terms of overall pricing, reflects that the process was indeed competitive. Therefore, LEI can conclude that the proposals we received as part of the RFP process were at the lowest reasonable cost given the benefits that we are expecting that Connecticut ratepayers will receive as a result of the contracts, as well as the overall qualities of the projects (such as environmental benefits, improved reliability, etc.).

Some stakeholders believe that the DPUC should procure up to the full Connecticut capacity requirements for the capacity and locational forward reserve markets. Indeed, the Investment Needs analysis issued by London Economics in the fall of 2006 also highlighted the need for about 600 MW of peaking capacity in Connecticut in the near term. However, the Investment Needs analysis was conducted solely on the basis of supply-demand dynamics, and intentionally only analyzed the quantity needed. The consideration of market prices, the investment costs of the quantity needed to clear the ISO-NE markets and eliminate the supply-demand 'gap', and therefore the benefits for meeting the markets' needs were deferred to the bid evaluation stage. The bid evaluation process built on the analysis in the Investment Needs Report by using the information gathered on each of the three key markets, the supply-demand forecast for each of the three markets and the projected capacity needs documented in the Investment Needs Report in combination with the prices received from bidders for their various project proposals to determine what the most cost-effective solution for Connecticut ratepayers would be.

Our Economic Analysis revealed that it was not cost-effective to procure the full 600 MW amount of peaking capacity needed to meet Connecticut's locational forward reserve requirements. Although substantial peaking capacity was bid into this RFP, the potential benefits of that peaking capacity did not outweigh its expected costs. Moreover, the locational forward reserve market costs are projected to only represent about 1% of total congestion costs (based on our forecasts for the modeling time horizon).[7] In other words, a project that reduced LFRM prices by 10% was going to produce an overall smaller ratepayer impact than a project that could reduce FCM or energy prices by the same relative amount. Indeed, some market needs traded off one market against another: for example, as energy prices fell, capacity prices had to rise to offset the anticipated revenue shortfall for some generators. Given all these consideration, it was not economically rational to attempt to reduce congestion costs by focusing primarily on the costs caused by the locational forward reserve market.

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7 The anticipated contribution of the Locational Forward Reserve Market to Federally Mandated Congestion Costs is projected to be higher in the early years, starting at 2.3% in 2007 but decreases to 0.6% in the later years of the forecasts.

2 Context and objectives

Reduced levels of infrastructure investment in recent years, in conjunction with structural changes to the New England-wide electricity market[8] and rising fuel prices have increased, and could conceivably continue to increase, what Connecticut residents and businesses pay for electricity. To address some of the underlying catalysts behind rising electricity prices, the Connecticut state legislature passed the Energy Independence Act (EIA) in January 2005, authorizing the Department of Public Utility Control (DPUC) to carry out a competitive procurement process in order to bring additional generating and demand-side capacity online and to reduce the impact of certain wholesale electricity market rule changes on Connecticut ratepayers.

The EIA specifically targeted the reduction of what are called Federally Mandated Congestion Charges (FMCCs). Congestion charges are generally the result of the need to use higher cost local generation when lower cost generation can not be imported from other zones (within New England) or regions (outside New England). The state's statute defines FMCCs as: "any cost approved by the Federal Energy Regulatory Commission as part of New England Standard Market Design including, but not limited to, locational marginal pricing and reliability must run contracts." Congestion charges are mainly associated with different electricity product markets, including energy (each hourly unit of electricity generated), capacity (the potential to produce electricity), and reserves (a product needed to ensure the integrity of the transmission grid)[9]. Energy is the largest contributor to congestion costs at 82%; capacity is the next largest at 17%; and, locational forward reserves only contribute about 1% (based on LEI's forecast of congestion costs over the 2007-2021 time horizon).[10] These three products are (or, in the case of capacity, will be) procured using locationally-differentiated prices.[11] Thus, increasing the in-state supply for resources that can meet the energy, capacity, and reserve needs of Connecticut will generally help to decrease costs for Connecticut ratepayers.

As required by the EIA, the DPUC's procurement process was open to both supply side (generation) and demand side (energy efficiency and demand response) resources. The EIA also described how the DPUC should select the best capacity projects for the state: projects

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8 See Footnote 1.

9 By reserves we are referring to the operating reserves procured in the Locational Forward Reserve Market (LFRM).

10 LFRM's percentage contribution is greater in the earlier years of the forecast, starting at 2.3% and decreases over time to 0.6% by 2021. FCM's contribution increases over time, starting at 10% in 2007 and increasing to 20% by 2020. Energy's contribution also decreases over time, starting at 88% in 2007 and decreasing to 79% by 2020.

11 Energy prices already vary by region within New England – the LMP is the price of energy and the congestion and marginal losses of delivering that energy. Load must pay the Connecticut zonal LMP, which is usually a higher than the New England-wide price. LFRM prices also vary by region, and there is both a Connecticut and a Southwest Connecticut regional price for LFRM currently. The Forward Capacity Market is being launched in 2010; it is still unclear whether or not Connecticut will have sufficient capacity to be considered part of New England or whether it will be considered its own import-constrained zone.

selected should increase reliability, minimize FMCCs, and should be procured at the lowest reasonable cost possible. The objective of this procurement process was not to resolve all supply deficiencies in Connecticut for the foreseeable future or to displace or replace wholesale electricity markets. Rather, this procurement process was meant to encourage the development of new or incremental capacity sooner than might otherwise occur, focusing on capacity that achieves the greatest net benefits for Connecticut ratepayers over time, while maximizing other state policy objectives.

3 Background

In light of the EIA, the DPUC launched a competitive procurement process to facilitate the development of incremental capacity in Connecticut as soon as practicable. LEI, on behalf of the DPUC, first conducted a detailed Needs Assessment[12], in which it analyzed the anticipated supply-demand balance in the different product markets that contribute most to congestion charges – energy, capacity, and locational forward reserves – over the next 15 years under four different scenarios. As the September 13, 2006 Decision notes, the purpose of the Investment Needs report was to "…set the stage for the RFP… It presents the range of incremental capacity that the state is projected to need, as well as the general type and location of such capacity needs, in order to ensure that Connecticut develops adequate supply to meet ISO-NE's expected procurement targets in the FCM, LFRM, and the Energy Market."

The analytical process behind the Investment Needs analysis involved extensive input from stakeholders and corresponded with the underlying assumptions used in the bid evaluation. Accordingly, the results of the Investment Needs were updated on December 5, 2006 so that bidders could integrate the updates in the development of their Financial Bids. The final conclusions of the analysis implied that Connecticut needs about 600 MW of capacity in the short term (starting as of 2007) and that its capacity need could increase to as high as almost 1,700 MW by 2021. The needs in the short term were driven largely by Connecticut state requirements for locational forward reserves while needs in the long term were driven by the Forward Capacity Market requirements.

Note, however, that the Investment Needs analysis was purely a supply-demand analysis; it analyzed only the quantity needs of the various ISO-NE markets and did not factor in the implications of the associated costs and benefits of such capacity needs. The objective of the bid evaluation was to expand on the forward-looking supply-demand scenarios created in the Investment Needs analysis and to project a range of future market conditions and market prices. These market prices would then determine the potential benefit of a project or group of projects. In addition, these same market prices, in combination with the prices bid in by the various projects, would define the costs of projects to ratepayers. The projected benefits and costs would then be used to identify the most cost-effective mix of projects to meet Connecticut's energy resource needs. Thus the ranges for procurement targets that were identified in the Investment Needs analysis were never intended to be and were never used as fixed RFP procurement targets. The ultimate determination regarding the bid selection was based on the project's (or projects') ability (abilities) to reduce total costs to Connecticut load, as compared to projections of costs to load if no projects were procured.

To minimize risk to the electric distribution companies who will be serving as the counterparties to these contracts, the contracts for the winning projects were structured in the form of a financial Contract For Differences (CFD), to be settled against ISO-NE's Forward

12 The Needs Assessment is available for download at: http://www.connecticut2006rfp.com/other_docs.php. The December 5th update is available at: http://www.connecticut2006rfp.com/rfp_docs.php.

Capacity Market and (at the bidder's choice) against the ISO-NE's Locational Forward Reserve Market and ISO-NE's day ahead energy market. The winning bidder (the supplier) is required by the terms of the contract to participate in the ISO-NE markets against which the contract settles. The contract has a two-way payment structure. The supplier will receive the payments it obtains from participating in the ISO-NE markets. Each month there will be a settlement process: if the annual contract price (the price the supplier bid into the RFP) is above the actual market clearing price in the relevant ISO-NE market(s), the buyer will true-up the supplier such that the buyer receives the full annual contract price. If the annual contract price is below the actual market clearing price, the supplier will pay the buyer the difference.[13]

There are numerous benefits to using a CFD structure. First, it requires that new capacity participate in wholesale electricity markets and therefore positively impacts market prices. This creates a "multiplier effect" which benefits ratepayers by decreasing the market price across the entire market, and thus lowers overall costs. Second, the settlement structure of the CFD also reduces direct costs associated with these contracts, although ratepayers pay for the remainder indirectly through wholesale market charges. Finally, the CFD structure also reduces incentives for winning projects to game wholesale electricity markets since their compensation is fixed for the duration of the contract.

On September 15, 2006, the DPUC officially launched its RFP to procure new or incremental capacity. By September 29, 2006, the bidder registration deadline, the DPUC had received 80 project registrations from more than 45 bidders. The next milestone for bidders was the submission of extensive documentation demonstrating the financial and technical capability of the bidder as well as a detailed description of the project and proposed financing. By October 13, 2006, the qualification deadline, the DPUC had received 33 qualification submissions from 20 bidders representing a combined total of more than 6,000 MW[14]. In the final phase of the RFP, the Financial Bid Submission on December 13, 2006, when bidders submitted their actual Financial Bids and posted significant security deposits, the DPUC received more than 20 Financial Bids from 15 different bidders. The submitted Financial Bids covered the full spectrum of resources that the RFP was designed to solicit - demand-side reduction, conservation and energy efficiency technologies, new gas-fired and oil-fired electricity generators and repowering of existing and retired or deactivated generation units. The 15 entities who submitted Financial Bids constituted a wide array of participants in the electricity sector, ranging from international independent power producers, to local generation developers and local utilities. There was also a strong response from a variety of companies focused on demand side activities.

This RFP process conformed to the DPUC's procurement principles and standards developed in Docket No. 05-07-20, *Development of a Process and Standards for Competitive Solicitation of Long-term Projects to Reduce Federally Mandated Congestion Costs,* issued on December 28, 2005. All bidders were given access to the same information at the same time; all bidders were required to submit documentation by the same deadlines; and all winning bidders were required to sign

13 For more information on these standardized contracts, please download them from: http://www.connecticut2006rfp.com/rfp_docs.php#2.

14 Note that some of these projects were duplicative of one another.

the same standardized contracts. As a result of (1) the fact that these competitive criteria, among others, were strictly adhered to, (2) the number of qualifying proposals that were submitted, and (3) the range and consistency of the Financial Bids (i.e., the price in terms of $/kW that bidders bid in the RFP process), LEI can conclude that the procurement process was competitive. Therefore, it is expected to provide for a least cost solution. Further, LEI coded each Financial Bid with a random three-digit code upon receipt of the Qualification submissions. These codes were used to identify the project through the RFP and bid evaluation process and in all LEI communication with the DPUC. Thus, decisions regarding final recommendations to the DPUC were made without reference to the bidder's identity, ensuring impartiality in the process.

From December 13, 2006 through May 2007, LEI analyzed the Financial Bids, conducting a sophisticated and detailed bid evaluation of each individual bid, and a variety of different portfolios. This report presents the summary of that analysis and details LEI's recommendations regarding the winning projects of the RFP process – it has been revised from the May 7, 2007 to reflect modifications to the LFRM cleared quantity at the unit level[15]. Note however that due to the confidential nature of the information submitted by bidders in the RFP process that LEI has had to balance the need for transparency with its obligations to protect the bidders' confidential data. In this revised report in response to stakeholder questions, LEI has expanded upon its explanation of certain issues (without breaching the confidentiality agreements it signed with the bidders) in order to explain its assumptions and analysis in more detail.

[15] A lookup formula had referenced a wrong column in the LFRM model and had incorrectly linked LFRM cleared quantity with the FCM model for some units (approximately 50 units mostly located outside of Connecticut). This slight difference has not affected the ranking of the portfolios or our recommendation for the selection of Portfolio 89.

4 Methodology for bid evaluation

The objective of the bid evaluation process was to ensure that LEI identified projects that best met the needs of Connecticut ratepayers and the objectives of the EIA - reducing total congestion costs and improving reliability at the lowest cost possible. At the same time, LEI wanted to be sure that the bidders proposing those projects were financially and technically capable of developing, constructing and operating those projects such that the anticipated benefits from those projects and represented in the bid submissions are likely to be realized. In addition, given the all-source nature of the RFP process, LEI wanted to analyze different types of resources on an apples-to-apples basis, such that certain types of technology were not disadvantaged. The requirement that all selected projects endorse and agree to sign the same master contract, which contained standardized performance and security requirements, was one way LEI ensured that projects could be compared against one another. LEI designed the overall bid evaluation framework to address these needs.

4.1 Overview of bid evaluation

There were three general phases to the RFP process: Bidder registration (all bidders had to be registered in order to have their proposals assessed); the Qualification Phase, where the bidder teams' financial and technical abilities were carefully assessed; and the Bid Evaluation Phase, where the technical and financial proposals were assessed. Bidders had to be classified as "qualified" by LEI after the Qualification Phase to have their technical and financial bids analyzed. All bidders submitting conforming Financial Bids were ultimately deemed "qualified" by LEI, although some bidders were required to submit additional documentation to support their qualification package.

The Bid Evaluation process entailed several components: the Economic Analysis, which focused on identifying the projects and portfolios that

> (a) reduce congestion charges the most after factoring in the contracts costs of each project and portfolio and the services being rendered by the selected project(s);
> (b) improve reliability and offer ratepayers other benefits based on state policy priorities (as documented in the Other Factors analysis, which assessed how projects and portfolios met other Connecticut policy priorities, including improving reliability);
> (c) pass technical feasibility analysis and project execution risk analysis;
> (d) could be deemed to be deliverable and are likely to make the FCM Qualification process; and
> (e) maximize net benefits in the Portfolio Analysis, which focused on understanding which combination of projects optimized the portfolio's economic, policy and technical results; and,

(f) contribute to social welfare by reducing market power - can the winning portfolio enhance or reduce the potential for market power abuse in the wholesale electricity market.

Figure 2. Overview of RFP evaluation framework

Bidder registration

Qualification Phase

- Is Bidder Team financially capable of mounting and operating project?
- Is Bidder Team technically capable of mounting and operating project?

Bid Evaluation Phase

1. **Are proposals complete?**
2. **Do proposals meet minimum requirements?**
3. **Do proposals meet technical requirements?**
4. **Assessment of economic and other factors**
   - **Economic analysis**
   - **Other Factors analysis**
   - **Project execution risk analysis**
   - **Deliverability and FCM Qualification analysis**
   - **Portfolio analysis**
   - **Assessment of market power risk**

4.2 Creating the shortlist

The objectives of the shortlisting process were to ensure that all bids were conforming to the requirements of the RFP and to identify any projects that were so clearly economic that no detailed analysis was required to reject them. The Economic Analysis conducted by London Economics, as is described in more detail in Section 4.3, was extremely detailed and time consuming. For example, determining a given project or portfolio's net benefit required almost 10 hours of a computer's running time.

The short-listing process had two phases. LEI first analyzed Financial Bid submissions received December 13, 2006 to ensure they conformed to the requirements of the RFP. Three submissions were ultimately disqualified from the process in January 2007 due to non-conforming proposals. Two bidders submitted proposals contingent on significant changes to the standardized contracts and one bidder required DPUC contract approval eight months earlier than planned. The bidders submitting these three non-conforming proposals refused to make timely adjustments to render them conforming and were therefore disqualified from this RFP process.

Second, LEI analyzed the conforming Financial Bids, comparing projects within their class of technological peers[16] from both a financial and a technical perspective to identify any projects that should not be included on the shortlist. This shortlisting process was methodical and conservative, eliminating only those projects whose costs far exceeded their peers' costs or other relevant benchmarks. LEI acknowledges that proposals with contract costs that are substantially higher than expected market prices have the potential to create a rippling effect in the market and therefore lead to overall benefits to Connecticut ratepayers that would exceed their contract costs. Hence, the comparative approach used in creating the short-list was extremely important. If there were other proposals with similar characteristics whose pricing was significantly more favorable, it was unlikely that the project with the unfavorable contract costs would ever be a contender for the winning portfolio.

The financial comparative analysis focused on contrasting the present value of each project's annual total costs to other projects of that same technology in order to identify "outliers" whose bids were extremely uneconomic. LEI also evaluated each project's proposed Financial Bids against other independent indicators, for example, comparing contracts costs per kW and per kWh against the levelized costs of other state programs and against a technology-specific notional threshold contract cost level[17], above which negative net benefits were possible. More specifically, LEI followed a two-pronged approach in the short-listing preliminary economic/cost assessment:

1) Approach 1 - NPV of Gross Contract Cost: LEI ranked the different projects in each of the four technology classes from 1 to 3 (1 being the best and 3 being the worst) based on the NPV of the contract costs (estimated by taking the offered Annual Contract Quantity and multiplying it by the Annual Contract Prices for FCM, and where relevant, for LFRM). This NPV was then normalized across all projects by dividing it by each project's average annual kW of FCM Contract Quantity. Projects that were given a rank of 3 were generally "expensive" outliers and we therefore used a rank of 3 as an elimination factor.

2) Approach 2 - Notional Thresholds for Contract Prices: based on modeling runs involving hypothetical projects, we estimated Contract Prices for each project through backwards deduction (based on its technology and size) above which we would typically expect a higher likelihood of negative net benefits given the average

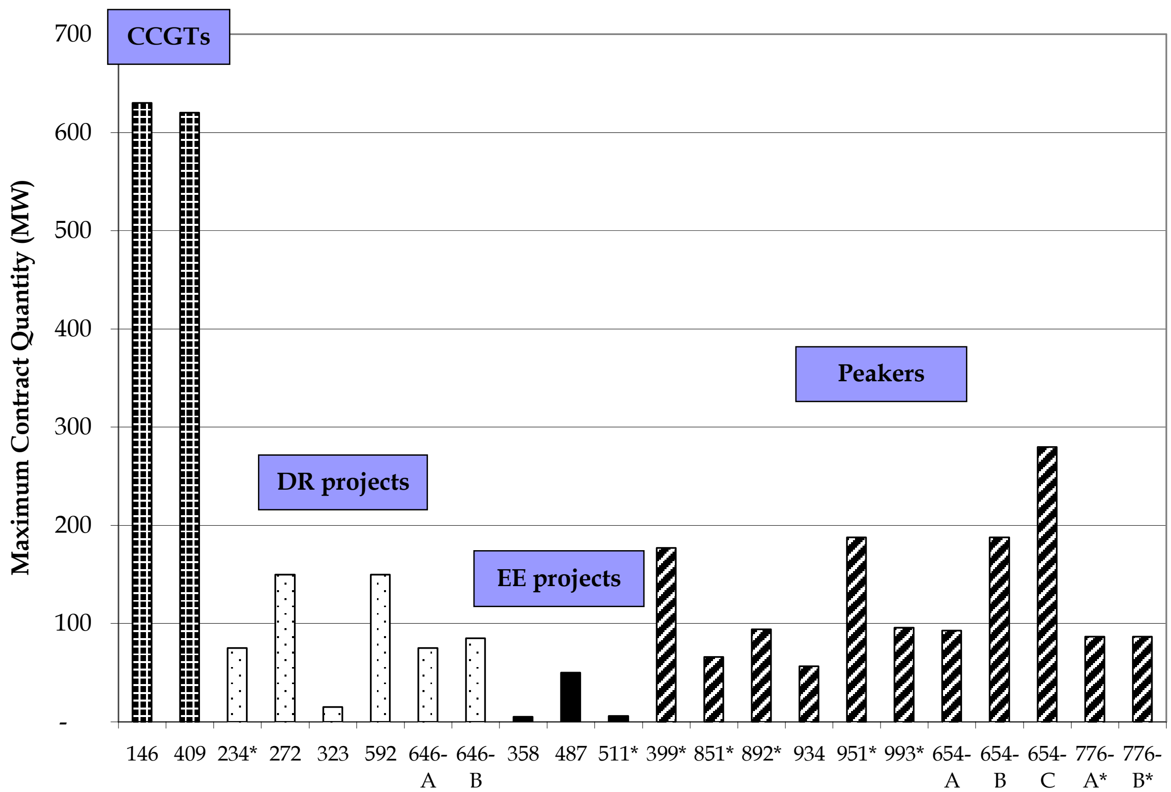
16 We grouped the projects into four categories: baseload generation, peaking generation, demand response, and energy efficiency.

17 In order to provide a reference point for systematically distinguishing between high cost and lower cost projects, we imputed average contract price levels above which we would anticipate negative net benefits to ratepayers because contract costs would outweigh potential market benefits. For example, peaking generation projects were anticipated to have higher threshold levels than demand response resources because they would likely impact more markets and therefore produce greater benefits to ratepayers than demand response resources, which were primarily expected to earn benefits associated with the capacity market.

level of the contract price. After determining the notional threshold levels, LEI then compared this threshold Contract Price to the average of the offered Contract Prices and eliminated projects whose offered Contract Prices exceeded the threshold.

The preliminary technical assessment included a "fatal flaws" review (after which, some bidders were asked to provide additional information about the technical specifications of their proposal) and first-stage ranking of projects within each of the four classes for project execution risk (which was later refined once bidders responded to technical questions arising from the "fatal flaws" review).

Figure 3. Capacity of conforming Financial Bids organized by technology and labeled using anonymous three-digit bid IDs (MW)



Note that projects with an asterisk (*) behind their bid code are located in Southwest Connecticut.

Out of the 22 conforming Financial Bids (a few of which were mutually exclusive), LEI eliminated seven projects based on the above financial review (in consultation with the preliminary technical assessment). None of baseload generating projects were eliminated as their proposed contract prices were relatively close and further analyses were required. The seven eliminated projects had contract costs that were at least 20% higher on a present value basis than the average contract costs of projects in their respective categories or other benchmarks.

- Two demand response projects were eliminated: Project 646-B's present value of contract costs was almost 20% higher than the average for demand response projects while Project 323's present value of contract costs was almost 70% higher.
- Three peakers were eliminated: Project 934's present value of contract costs was more than 100% higher than the average level for the peaking generation class, while Project 654-A's present value of contract costs was 28% higher than the average level (note that Project 654 was offered in three mutually exclusive variations and the other two options, which were priced under more attractive terms, were not eliminated and therefore remained on the short list). Project 399's contract costs were higher than the notional threshold contract price level for peakers ($17/kW-month), therefore, that project was eliminated.
- Finally, two energy efficiency projects were eliminated – these were the two highest cost proposals for this class of projects. Proposed contract prices for these energy efficiency projects were extremely high and far exceeded prices paid for energy efficiency in other state-run programs in $/kWh terms.

The comparison of the conforming projects' NPV of contract costs as compared to the notional threshold is shown in the graphics below.

Figure 4. Shortlisting process for the conforming baseload bids

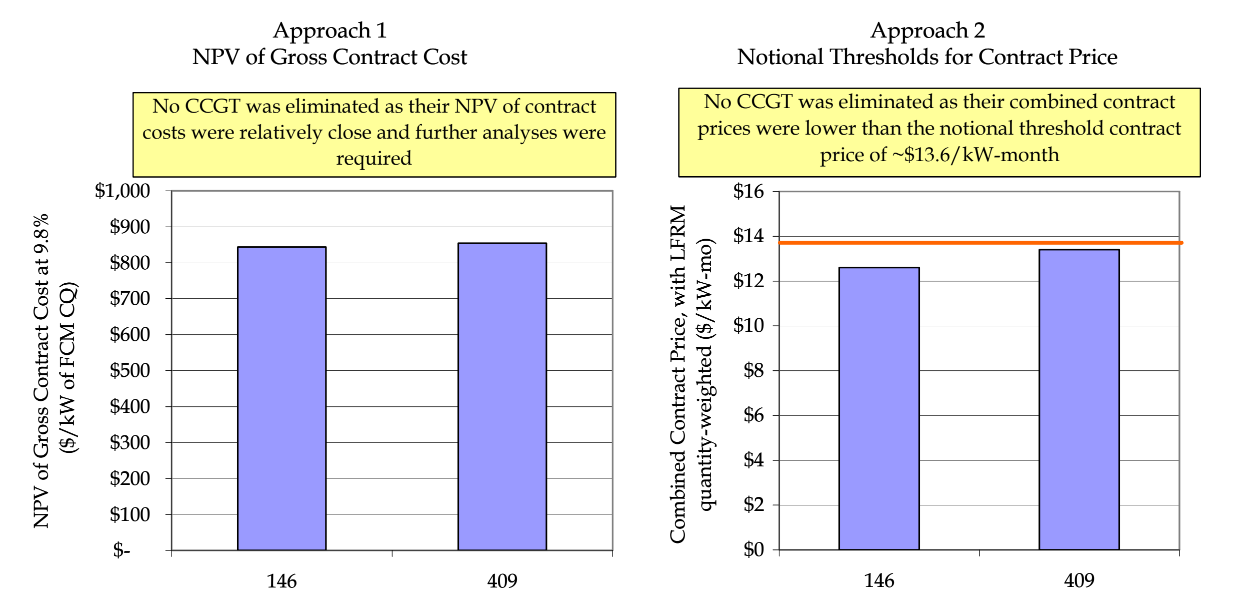


Figure 5. Shortlisting process for the conforming DR bids

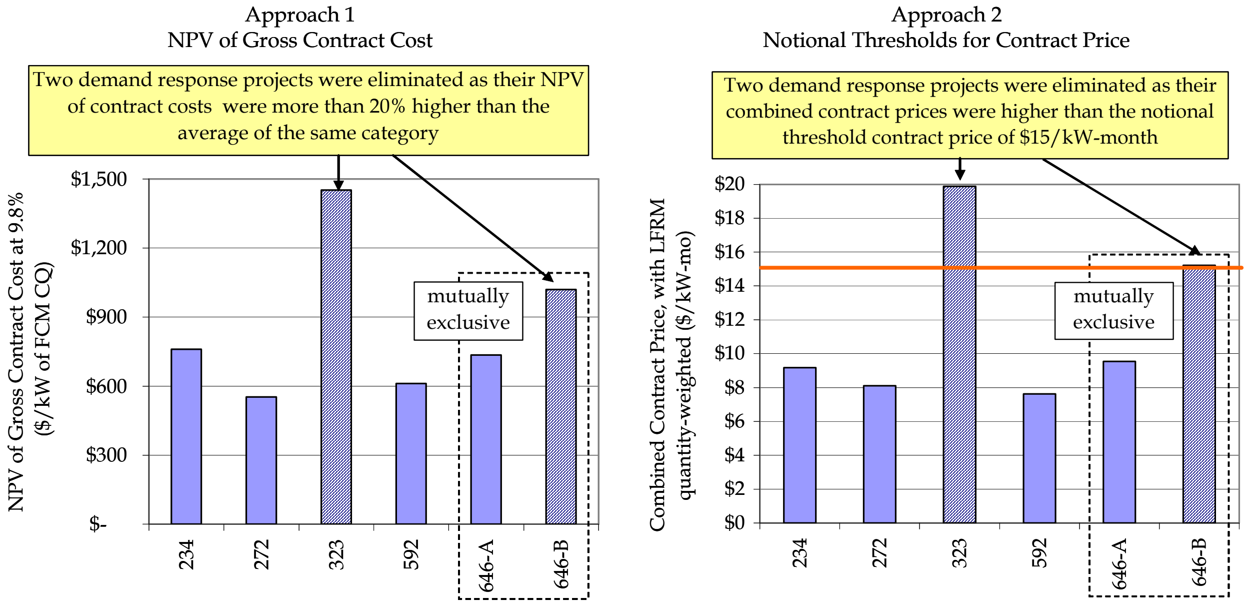


Figure 6. Shortlisting process for the conforming peaker bids

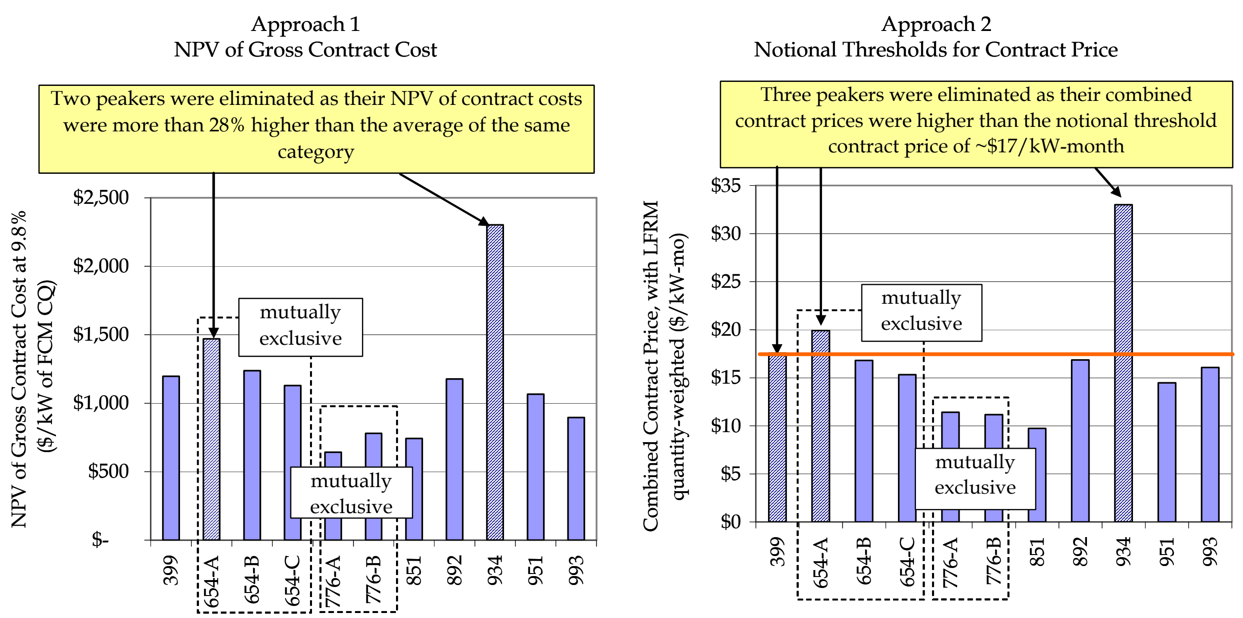
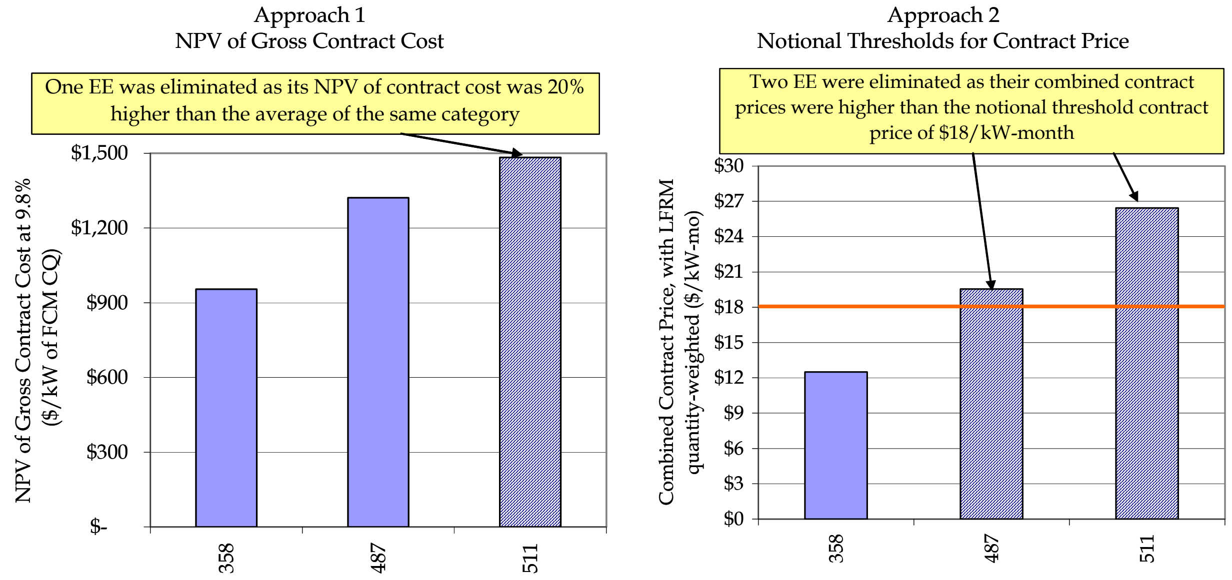


Figure 7. Shortlisting process for the conforming EE bids



Note that the line on the right chart represents the notional threshold contracts costs by technology above which the project was unlikely to create positive net benefits. Highlighted bars are the projects that were not shortlisted.

4.3 Economic Analysis overview

The objective of the Economic Analysis was to determine the impact that each project could have on price in the key ISO-NE markets – energy, capacity, and locational forward reserve - after factoring in the costs each project would incur from the ratepayers' perspective. The best way to achieve this objective was to use a Cost-Benefit framework where the total costs of the project were subtracted from the total benefits that the project is estimated to create to derive the net benefit of the project. Therefore, there were three main conceptual components to the Economic Analysis:

- **The calculation of Gross Benefits:** Did the project result in price decreases and reduced costs to load for Connecticut ratepayers in these key ISO-NE markets, and, if so, by how much?

  In order to isolate the impact of a project or group of projects on FMCCs paid by Connecticut ratepayers, a set of future market prices was developed without any of the projects under nine different scenarios which represented realistic different possible market outcomes[18] (these were referred to collectively as the "baseline"). Then these

18 The nine scenarios were weighted to reflect the DPUC's views on the likelihood of their occurrence and in light of the DPUC's objectives (minimizing costs and volatility). All analysis in the bid evaluation was conducted by using the weighted average of the nine scenarios, which are described in more detail in Section 4.3.1.

future market prices were re-estimated taking into account the project (or group of projects) being analyzed. LEI calculated the annual FMCCs to Connecticut load from the key ISO-NE markets (energy, capacity and locational forward reserves[19]) under the "baseline" market prices and based on market prices taking into account the project or group of projects. The benefit of a project (or group of projects) was the costs savings that the project (or group of projects) was forecast to produce across the three ISO-NE markets – namely the expected reduction in the overall FMCCs payable by Connecticut ratepayers over the modeling horizon.

- **The calculation of Contract Costs:** How much would it cost Connecticut ratepayers to procure the project?

  The calculation of contract costs was complicated by the fact that the contract entails a Contract For Differences structure, as described in Section 3. The Contract For Differences structure means that there is a settlement process each month between the market clearing price and the price that the bidder bid in its Financial Bid. The contract costs of a project are ultimately determined by the difference between the project's price from its Financial Bid and the forecasted market prices in the Forward Capacity Market (and, where relevant, the Locational Forward Reserve Market and the day ahead energy market) multiplied by its warranted Contract Quantity (the amount the bidder promised to deliver to Connecticut in the Financial Bid).

- **The calculation of Net Benefits:** After paying for the project, how much benefit do Connecticut ratepayers ultimately receive?

  Total discounted contract costs for a project (or a group of projects) was then subtracted from the total discounted value of the FMCC savings (the "gross benefits") to determine net benefits. Net benefits were analyzed on a dollar per kW of installed capacity (or load reduction) basis when analyzing individual projects. Net benefits were analyzed both on a total dollar million basis as well as in terms of dollars per kW of installed capacity when analyzing the portfolios. LEI's objective in the Economic Analysis was to maximize these net benefits on behalf of Connecticut ratepayers.

An example of the cost-benefit analysis is shown in the box below.

[19] LEI employed its proprietary least cost dispatch model, PoolMod, to analyze energy prices in conjunction with two customized models that it created to simulate the Forward Capacity Auctions and Locational Forward Reserve Market. See Section 4.3.1 for an introduction to these models and see the Appendix for a detailed description of all three models and their key assumptions

Example of Cost-Benefit Calculation:

For each product market - energy, capacity, and LFRM - we calculated the cost to Connecticut load without the project and then subtracted the cost to Connecticut load with the project to determine that project's gross benefits. We then deducted the costs of the contract in order to realize the net benefits of that project.

To calculate **energy benefits**, assuming the average cost of electricity in Connecticut without any project in 2010 is $80/MWh and that the energy consumption in that year is 36,000,000 MWh. Then the cost of energy to Connecticut ratepayers in 2010 is $80/MWh * 36,000,000 MWh = $2,880 million. Assume that the project is expected to reduce energy price by $1/MWh on average. Therefore energy prices with the project are expected to be $79/MWh. Therefore the total cost of energy to load would be equal to $79/MWh * 36,000,000 = $2,844 million dollars. Thus, the energy benefits that Connecticut ratepayers receive as a result of this project is equal to what they would have paid without the project minus what they would anticipate paying with the project, or $2,880 million - $2,844 million = $36 million for 2010.

For **capacity benefits**, the calculation is essentially the same though there are some nuances to the Forward Capacity Market that are not addressed in this simplified example. Assume the Forward Capacity Market clearing price for 2010 is projected to be $9/kW-month without a project and $8/kW-month with a project. The benefit to Connecticut ratepayers would be the difference in the two clearing prices; $9/kW-month - $8/kW-month multiplied by the Connecticut peak load share of the New England ICR, which in our example year of 2010 is 27% of 29,185 MW. Thus, capacity benefits of the project are equal to $1/kW-month * 1,000 * 12 months * 27% * 29,185 MW = $94.6 million.

The **LFRM benefit calculation** is more complicated as it takes into account the relative contributions of each of the four LFRM zones (Boston, Southwest Connecticut (which is nested in the Connecticut zone), Connecticut, and rest of New England) to the total cost of providing operating reserves. That said, the benefit to Connecticut ratepayers is still the cost of purchasing operating reserves without a project, less the cost of purchasing those reserves with the project. Let's assume the cost of reserves for the state of Connecticut (including both SWCT and Connecticut zones) in 2010 without a project is $20 million, but a project reduces that cost to $19 million. Then the benefit to Connecticut ratepayers resulting from that project is $1 million.

To calculate the project's **contract costs**, let us assume that the hypothetical project is 600 MW (which is equal to 600,000 kW) and has contracted to settle against the FCM market clearing price for $10/kW-month. The market clearing price in the FCM for 2010 is $8/kW-month in the above example. Thus, the payments to this project (cost of the project to Connecticut ratepayers) in 2010 are the difference between the project contract price and the FCM clearing price, ($10/kW-month - $8/kW-month) * 600,000 kW * 12 months per year = $14.4 million.

The **net benefit** to Connecticut ratepayers in this example then is the sum of the benefits that the project produced in each of the three product markets minus its settled contract costs: $36 million (energy benefit) + $94.6 million (capacity benefit) + $1 million (LFRM benefit) - $14.4 million (contract cost) = $117.2 million in net benefits for 2010.

Because of the long term nature of most capacity projects, different contract start and end dates, and the fact that timing of costs and benefits differed even on an individual project basis, LEI applied a Net Present Value (NPV) method for discounting future benefits and costs to 2007 dollar terms. Under the NPV methodology, the discounting allowed LEI to compare projects and portfolios against one another fairly and also incorporated the ratepayers' risk appetite and time value of money preferences - projects providing more immediate benefits were more highly valued than those that only provide benefits in the distant future. LEI used a single discount rate that is consistent with the allowed rate of return of the electric distribution companies in Connecticut (9.8%).

Note that for energy efficiency and demand response projects, project impacts were simulated through assumed reduced electricity demand and consumption (as appropriate per terms of the technical description submitted in the technical proposal). The reduced energy consumption could produce a reduced market price, similar to how certain generation projects affect markets. In addition, energy efficiency projects produce energy savings, which we refer to as a quantity impact. At the individual ratepayer level, some of the energy savings are offset by the cost of implementation and only accrue to a limited subset of customers. Therefore the energy market benefits to Connecticut ratepayers on a statewide basis were analyzed with and without the quantity impact.[20]

In addition, the RFP allowed bidders to propose a Call Option for additional consideration by the DPUC. This Call Option provided ratepayers with a hedge against high energy prices resulting from tightening supply-demand conditions. In order to evaluate the potential benefits of the Call Option to ratepayers, LEI estimated the underlying value of the Call Option using an adjusted Black-Scholes option pricing model, taking into account the strike price that the Bidder submitted in the proposal, the energy market price forecasts developed (as described above), and volatility estimates derived from historical price trends, adjusted for expected structural changes in New England market design. The proposed Supplemental Capacity Payment was then deducted from the estimated value of the Call Option to derive a net benefit figure for this Call Option component, which was then discounted to 2007 terms using the 9.8% discount rate used for the rest of the Economic Analysis.

4.3.1 Overview descriptions of models used

ISO-NE operates four different product markets; energy, locational forward reserves, capacity (soon to be replaced with the new Forward Capacity Market), and a regulation market. We model the first three of these wholesale markets using forward-looking models that combined simulation and, where appropriate, econometric-based tools. Please refer to Section 7 for more detailed descriptions of the models and modeling inputs.

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20 Note that in the sake of providing a conservative analysis, we have presented most results throughout this paper *without* the quantity impact. Only where explicitly specified in this report do the numbers reflect the quantity impact. Our recommendation is based on consideration of the net benefits with and without the quantity impact.

We simulate the energy market using our proprietary hourly dispatch model, PoolMod. Using very detailed (unit level) inputs, PoolMod finds the least cost unit of generation to meet the demand in each hour, while also enforcing plant maintenance schedules and forced outage rates, as well as other critical technical details, like transmission thermal limits of interties, flexibility conditions of units, and hydroelectric energy constraints. The unit of supply (whether it be generation or a demand resource) that can satisfy the demand in each hour at the least cost establishes the market clearing price in that hour. The model also takes into account constraints across transmission interfaces and economic imports and exports with neighboring regions. Transmission constraints may cause price separation between areas or zones, especially during high demand periods. As discussed later in the report, the Economic Analysis anticipates substantial energy benefits from the baseload projects and the portfolios. By adding new - more efficient - generation projects to the "supply stack" (which is composed of the existing supply resources in that system), the resulting market clearing prices in the energy market decrease. In other words, the new resources displace existing resources and, based on their relatively higher efficiency and lower short run marginal cost, produce a lower market clearing price or locational marginal price (LMP). For example, on average across the nine scenarios, Portfolio 89 produced reductions in energy prices of $1.7/MWh between 2010 and 2025 in Connecticut.

We also modeled the Forward Capacity Market (FCM), by simulating the Forward Capacity Auctions using the terms defined in the Settlement Agreement and draft market rules awaiting FERC approval. This model is essentially a supply stack model, wherein a market clearing price is set by the least cost bid into the auction in a given year that can satisfy demand (defined as the Installed Capacity Requirement (ICR) or the Locational Sourcing Requirement (LSR) as appropriate). Supply resources are "stacked" from lowest to highest by their net revenue shortfall.[21] This is consistent with rational bidding behavior and with the expected auction dynamics. The model also includes modules for calculating the Cost of New Entry (CONE) in each year and Capacity Zone, determining whether there is Inadequate Supply, when a zone may be designated as a separate Capacity Zone, and for applying special pricing rules in the event they are warranted as defined in the draft market rules.

The forward reserve market is designed to compensate generating units for holding their capacity in reserve to protect against the possibility of a second contingency event. The LFRM model creates a supply stack based on the net revenue shortfall of the units (or partial units) that can participate in this market in order to determine the least cost supply resources. Unlike the FCM, however, a plant must have the operational capability of providing second contingency protection (ability to start or increase output quickly). This disqualifies a great deal of capacity from participating in this market. Furthermore, participating in LFRM is, under normal market conditions, mutually exclusive from participating in the energy market since this forward reserve market is designed to hold capacity in reserve in case of emergency. Thus, a great quantity of capacity does not offer itself into the forward reserve market because it has a greater opportunity to earn revenue in the energy market than in the LFRM. The LFRM model

21 The net revenue shortfall is simply the money that it needs in order to avoid retirement after accounting for its profits from energy and/or LFRM sales.

thus, must determine the amount of capacity that will participate in the simulated auction in each year.[22] From this simulation, we are able to determine the offer quantity and supply stack for the LFRM. The LFRM price premium was then calculated using a calibrated econometric model that relates the price premium in the LFRM market (above the capacity price) to the level of supply and the procurement target. Effectively, as competition increases, premiums are expected to be compressed.

Together, these three models provide the inputs needed to determine the costs to load from each market and to estimate each project's and portfolio's ability to reduce that cost to load and create ratepayer benefits.

We provide a more detailed description of each of the three markets, how we modeled them, and our fundamental assumptions for each in Section 7 in the Appendix.

4.3.2 Assumptions underpinning Economic Analysis

In analyzing the Financial Bids, LEI wanted to be sure to capture the potentially different market price outcomes driven by differences in supply and demand conditions, future environmental regulations, fuel prices, and transmission system upgrades. As such, LEI developed a baseline analysis for the bid evaluation which was comprised of nine different market outlooks under which LEI analyzed all of the projects and portfolios. This nine-scenario baseline is consistent in an expanded format with the four fundamental scenarios underlying the investment needs analysis.

The nine scenarios include a wide range of possible future market conditions, some of which are more likely to occur than others, based on currently available information. In order to provide for a meaningful comparative analysis, LEI calculated a weighted average net benefit based on weightings applied to the results of each of the nine scenarios. The weightings were determined through a qualitative assessment of the likelihood of its occurrence and its importance in terms of DPUC objectives (minimizing high prices and price volatility). The weightings also reflect ratepayers' risk aversion to high and volatile market prices. The nine scenarios that comprise the baseline are listed below. The percentage in parentheses after each scenario indicates its weighting in the Economic Analysis.

- **Scenario 1:** Base supply-demand conditions with high fuel prices (7.5%)
- **Scenario 2:** Base supply-demand conditions, base fuel prices (30%)
- **Scenario 3:** Base supply-demand conditions, base fuel prices and delayed commercial operation of planned transmission projects in New England (2.5%)
- **Scenario 4:** Base supply-demand conditions with low fuel prices (5%)

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22 Unlike the function of the actual LFRM, however, we only simulate one auction per year (during the summer period) rather than two.

- **Scenario 5:** Base demand with moderately delayed new investment (supply coming in three years later than in base case), base fuel prices (10%)

- **Scenario 6:** Low demand with moderately accelerated new investment (supply comes online one year earlier than base case), base fuel prices (10%)

- **Scenario 7:** Low demand with moderately accelerated new investment (supply comes online one year earlier than base case), low fuel prices (10%)

- **Scenario 8:** High demand with delayed new investment (supply comes online four years later than base case), high fuel prices (12.5%)

- **Scenario 9:** High demand with delayed new investment (supply comes online four years later than base case), base fuel prices (12.5%)

The supply and demand assumptions were developed to reflect a rich spectrum of supply-demand conditions going forward, including everything from an excess capacity situation (where there is more generation than demand, potentially depressing prices) to an under-capacity situation (where demand is at or exceeds the amount of generation in the system, leading to scarcity and high prices). The demand assumptions were based on the "50/50" reference case used by the ISO-NE for system planning, which is ISO-NE's base case. The high and low demand scenarios were developed using ISO-NE's high and low economic demand growth cases, which deviated from the "50/50" reference case by as much as 2,480 MW and 13,667 GWh by 2015. Thus, the assumptions underlying the bid analysis are consistent with the assumptions used for long term system planning and resource adequacy analysis.

The fuel price projections used in the bid evaluation were developed from various reliable input sources, such as short term forwards from NYMEX, long term fuel price forecasts produced by the US Department of Energy's Energy Information Agency (EIA) as well as historical data on delivered fuel costs to specific plants in New England. The base case gas price forecast was developed using NYMEX forwards for the first six years of the forecast timeframe (2007-2012) and then blended into the long-term forecast from the *EIA Annual Energy Outlook 2007*. The base case oil price forecast was based on forward prices for various oil products from NYMEX, using the *EIA Annual Energy Outlook 2007* to calculate pricing differentials between the various oil products and to calculate an implied projected growth rate in prices. The base case coal price assumptions were based on the average delivered price of coal (for the period January 2004 through July 2006) to each coal-fired plant in New England, escalated to nominal terms using the annual rate of change implied in the coal price index and inflation rate from *EIA Annual Energy Outlook 2007*.

LEI then created low and high case fuel price projections by adjusting the base case price based on historical price forecast errors. Our objective in developing the low and high fuel price cases was to test the impact that significantly different fuel price conditions could have on the wholesale electricity market. Thus, while the low, base, and high fuel prices start at the same price point in 2007, each case follows a distinctly different trend over the 15 year timeframe. For example, by 2021, the nominal gas price forecast ranged from a low of \$3.60/MMBtu to a high of \$23.78/MMBtu with a base case price of \$9.51/MMBtu. Note that the low gas price is reflected only in Scenario 4 and 7, which had a 5% and a 10% weighting, respectively, based on the relatively low probability that these outcomes are likely to result.

In the bid evaluation, transmission planning is expected to proceed as planned according to the most recent estimates from ISO-NE. However, the effects of a one-year delay to the Northeast Reliability Interconnect Project and a two-year delay to the Southwest Connecticut Reliability Project Phase 2, were incorporated into Scenario 3. These delays are not considered likely based on currently available information and thus Scenario 3 has a relatively low weighting in our baseline analysis.

Finally, LEI also tested the ability of the various projects and portfolios to alleviate electricity supply interruptions by mimicking a gas shortage scenario used by ISO-NE in its planning process. To gauge the "gas shortage scenario" we derated each of the plants in New England that utilize pipeline gas. These plants' capacities were reduced by ~50%, creating a generation supply shortfall consistent with ISO-NE RSP analysis of the same issue, which assumes that all existing gas-fired capacity relying on interruptible fuel supply contracts would be curtailed. In total, New England gas-fired capacity was derated from 7,699 MW to 4,360 MW in 2007, where 4,360 MW includes 1,360 MW of LNG-fueled gas plants (Mystic 8 and 9) and 3,000 MW of pipeline gas units holding firm gas pipeline transmission contracts. We did not derate the bidder's projects since they are required to provide backup fuel capability. We then modeled the implications for supply interruptions (blackouts) using a 90/10 peak demand forecast assumption.

4.4 Other Factor Analysis

Approximately 15% of the final project score[23] in the Bid Evaluation was determined through the assessment of other criteria described in the EIA and other Connecticut state policy priorities, collectively referred to as Other Factors. Five categories of Other Factors were incorporated into the bid evaluation process – reducing environmental emissions, use of existing sites, improving fuel diversity, frontloading of costs, and other benefits[24], as is detailed in the graphic below. Based on the project details specified by Bidders in the Financial Bid Submissions, as well as the modeling results, projects were assigned points for each of these five Other Factors to derive a total Other Factors point score.

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23 The point allocation for Other Factors was determined by calculating the median of the weighted average net benefits of all projects and portfolios and using that median net benefit figure to estimate a dollar value for each Other Factor point such that on average the Other Factors dollar value was equal to 15% of the average. As such, some projects have Other Factors values that are higher than or lower than the 15% target.

24 Although certain of these criteria, such as the benefits of fuel diversity, a preference for Brownfield sites, and the costs of environmental emissions, are already represented in the economic assessment, they were also incorporated into the Other Factors category of the Bid Evaluation due to their importance in terms of Connecticut state policy priorities.

Figure 8. Overview of Other Factors

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

LEI allocated points using a pre-determined methodology for each category, described below:

- **Reduction in emissions in SO_2, NOx, and CO_2:** LEI measured the change in SO_2, NO_X, and CO_2 emissions resulting from each project on an annual basis across the New England market (each pollutant was treated equally on a quantity per kW of installed capacity (tons/kW) basis). The project or portfolio that reduced total emissions in New England the most was granted full points. Other projects and portfolios were granted points based on their comparative performance, using a percentile ranking.

  LEI used the historical emission rates of all generating plants in New England and the emissions rates provided by bidders for their projects in the energy model which allowed for the tracking of overall system emissions. The energy market model could therefore produce a forecast of the total emissions of SO_2, NOx, and CO_2 in New England without the project or portfolio and another forecast of emissions after the project or portfolio was introduced. The difference in emissions between these two forecasts is attributable to the specific project or portfolio being modeled. After calculating the annual difference between the emissions in these two forecasts, we discounted the difference to reach an NPV of emissions reduction for each pollutant. Using the weightings of the scenarios designed for the cost-benefit analysis, LEI catalogued the improvements in emissions caused by each project and portfolio by scenario. We then normalized the total emissions reduction for project size and restated the emissions reduction in terms of tons of reduction per kW for each pollutant. Each of the projects and portfolios were then ranked according to their relative ability to reduce the emission of each pollutant using a percentile ranking approach. Point credits for emission reduction were awarded based on the relative merits of a project or portfolio in reducing SO_2, NOx, and CO_2.

  The example below (Figure 9) shows the method for determining the emission reduction points for projects and highlights how different project/portfolio emission rates can lead to different overall rankings and points awarded for this category of Other Factor. In this example, two hypothetical projects were listed. In the top section, the reduction of emissions from each pollutant is presented (note that these numbers have been calculated by looking at the overall system's emissions with and without the project in the energy market simulations). The middle section of the graphic shows how these projects rank against all of the other projects and portfolios. In the case of Projects AAA and BBB (fictitious projects created for illustrative purposes only), they rank in the 68th to 66th percentile for SO_2 and NOx and rank 88th and 80th percentile for CO_2. Finally, points were awarded for each pollutant based on the percent rank and then equally weighted across the three pollutants to get the final point award so that none of the three pollutants would have greater weight than the others. Out of a total of 5 points, Project AAA was awarded 4.3 emission reduction points and Project BBB was awarded 3.8 points.

Figure 9. Sample calculation of the emission reduction point system based on two hypothetical projects

Emission reduction (wtd avg across scenarios)	Project AAA	Project BBB
SO_2 emission reduction (tons/kW)	8,575	7,980
NO_x emission reduction (tons/kW)	4,310	3,983
CO_2 emission reduction (tons/kW)	2,141,803	1,919,857
Total (tons)	2,154,688	1,931,820
Percentile Rank	**Project AAA**	**Project BBB**
SO_2 (%)	68%	66%
NO_x (%)	68%	66%
CO_2 (%)	88%	80%
Points Awarded (5 possible)	**Project AAA**	**Project BBB**
SO_2	4.0	3.5
NO_x	4.0	3.5
CO_2	5.0	4.5
Combined points (equal weight)	4.3	3.8

- **Use of existing sites and electric generation-related infrastructure:** Projects that were sited on existing electric generation sites received up to 2.5 points under the Other Factor scoring system in their Final Project Score (based on the 2.5% weighting factor for this category). Those facilities sited on locations that already possess electric generation infrastructure, and those projects that do not require such infrastructure (i.e., energy efficiency, conservation, and demand response projects), received 2.5 points. Projects on sites with certain existing supply infrastructure, like fuel supply and transmission infrastructure, but no generation infrastructure, received 2 points. Projects that rely exclusively on existing transmission (for example, use of the new transmission lines being built in SWCT) or generation infrastructure received 1 point. Projects that are using sites that have never been developed in the past for purposes of electric generation and will require new transmission or fuel supply infrastructure were allocated 0 points.

- **Benefits of fuel diversity:** Projects could earn up to 2.5 points for fuel diversity. Renewable projects, demand response, and energy efficiency projects were granted 2.5 points. Other non-natural gas or oil fired plants were granted 1.25 points, while power plants that are using gas or oil as their primary fuel source received no points.

- **Front-loading of costs:** Projects that reasonably allocated their contract costs in line with expected benefits (as measured by whether or not the net benefit in a given year is positive) received up to 2.5 points based on calculations from the Economic Analysis. The objective of this category was to penalize projects that tried to push most of their costs into the early years (without off-setting anticipated benefits) which could result in rate increases for Connecticut ratepayers.

Figure 10. Indicative illustration of front loading calculation for a hypothetical portfolio

Scenario	Years with positive NPV of Net Benefits in first 5 (yes=1, no=0)					Front loading years	Points Credited
	2009	2010	2011	2012	2013		
Scenario 1	0	0	1	1	1	**3**	**1.5**
Scenario 2	0	0	1	1	1	**3**	**1.5**
Scenario 3	0	0	1	1	1	**3**	**1.5**
Scenario 4	0	0	1	1	1	**3**	**1.5**
Scenario 5	0	0	0	1	1	**2**	**1.0**
Scenario 6	0	0	0	0	1	**1**	**0.5**
Scenario 7	0	0	0	0	1	**1**	**0.5**
Scenario 8	0	0	1	1	1	**3**	**1.5**
Scenario 9	0	0	1	1	1	**3**	**1.5**
Weighted Average							**1.25**

The front-loading analysis measured the number of years in the first five years after a project's or portfolio's contract start date where the weighted average annual net benefit across scenarios was positive. For each year with a positive net benefit, a project or portfolio was awarded 0.5 points. The process is illustrated in Figure 10 above. As the figure highlights, different market conditions greatly impact the economics of a project during its initial years of operation. The hypothetical portfolio presented is made up of a number of individual projects with different start dates. The hypothetical portfolio presented produced positive annual net benefits in 3 out of the first 5 years in 6 scenarios (Scenario 1, 2, 3, 4, 8, and 9), 2 positive annual net benefits in Scenario 5, 1 positive annual net benefit in Scenario 6 and Scenario 7. The portfolio thus earned between 0 and 1.5 points in each of the scenarios (1.5 points in each of Scenarios 1, 2, 3, 4, 8, and 9; 1 point in Scenario 5; and 0.5 points in each of Scenarios 6 and 7). The next step to determine front-loading credit was to average the points in each of the scenarios according to the scenario weights. This hypothetical portfolio was thus able to receive a total of 1.25 points from front-loading project benefits and producing positive net returns during its first five years of operation.

- **Other benefits:** LEI also granted additional points (up to a maximum of 2.5 points) for other benefits that a project can produce for the benefit of Connecticut ratepayers. Such other benefits included a project's impact on improving the reliability of the transmission network, eliminating the need for existing long term RMRs, and other innovative elements of the bidder's proposal. The assessment regarding reliability was conducted by PTI Siemens and the methodology and results of that analysis are summarized in its report which is appended to this document.

Once the total score for the Other Factors was established for all proposed projects, that score was weighed on an approximately 15% to 85% basis with the Economic Analysis (specifically the weighted average net benefit projections) for each proposed project and portfolio in the Final Project Scores. LEI calculated the median weighted average net benefit on a dollar million basis for all projects and portfolios. LEI also tested this methodology by calculating the value of Other Factors based on the average of the net benefits for all projects and portfolios, and by calculating the median and average using a dollar per kW basis. Incorporating these different options did not change the ranking of the projects, and LEI believes that the median of the weighted average net benefits as calculated on a dollar million basis is a more accurate figure to use, given the variation in the project and portfolio net benefits. LEI then estimated a dollar million value for the Other Factors for each project and portfolio such that the value of the median weighted average net benefit from the Economic Analysis represented 85% and the dollar million value of total Other Factors represented 15% on average (note that for some projects, Other Factors contributed more than 15% of the overall value). LEI ultimately allocated $3.1 million per point of Other Factors. Scores on Other Factors for individual projects ranged from 1.4 (Project 892) to 10.2 (Project 409). Scores on Other Factors for portfolios were generally higher because the portfolios were created from combinations of the top projects; they ranged from 4.9 to 11.4.

4.5 Technical issues

Several technical issues were analyzed during the bid evaluation process. LEI's objective in the technical analysis was to ensure that the project was technically feasible, that the project was likely to be developed within the timeframe specified in the proposal, that the project would be able to produce the amount of electricity (or energy savings) it was supposed to and that this electricity could be "deliverable" in the state of Connecticut, and that the project was likely to qualify for the ISO-NE Forward Capacity Market.

4.5.1 Technical feasibility and project execution risk

LEI used a team of experienced engineers (Inland Energy Consulting) to analyze the technical feasibility and project execution risk of each proposal. The technical feasibility analysis focused on ensuring that the project was appropriately designed and conceived given the latest information on industry practices and commercially reasonable standards; and that the project is likely to produce the overall level of energy (or energy savings) anticipated and proposed by the bidder. The project execution risk focused on the likelihood that projects would not come on-line at the date specified in their proposal and based on the technical terms specified for the project in the bid submission. Various factors were considered in this analysis including: current status of site control and environmental and site permitting; the expected ease of remaining environmental and site permitting; construction risk; and operating risk. Each project was ultimately given a score on its project execution risk, ranging from low to high.

Inland Energy Consulting has submitted a summary report of its analysis, which is appended to this report. The Inland Energy Consulting report has not been modified since it released on April 23, 2007.

4.5.2 Transmission interconnection and FCM Qualification risk

LEI also used a transmission system expert (PTI Siemens) to assess whether the top performing generation projects (1) were likely to interconnect to the ISO-NE system and be able to generate electricity for the Connecticut market and (2) whether they were likely to qualify at their proposed contract quantity for the ISO-NE Forward Capacity Market. PTI Siemens relied on the information provided by the bidder on its proposed project in conjunction with the information that was publicly available on the ISO-NE system to conduct this analysis. Projects were analyzed using the best available information as of April 2007 on the current proposed methodology for how ISO-NE will determine whether projects will qualify for the Forward Capacity Market, although the PTI Siemens also tested the potential deliverability of the projects under more stringent conditions.

The transmission and qualification assessments were directly incorporated into the bid evaluation process. The results from that assessments were also indirectly factored into the "Other Factors" analysis. Projects that could add capacity to the system without stressing it, and provide additional voltage support were granted additional points (ranging from 0 to 2.5) under the "other" Other Factors category for contributing to the enhanced reliability of the New England system. (Based on feedback after the Draft Decision, PTI also looked at the Demand Side projects on a qualitative basis, using their anticipated location (divided between Norwalk, rest of Southwest Connecticut, and rest of Connecticut) and their overall anticipated size (load reduction) to allocate reliability points to these projects, as well. A more detailed analysis was not possible given that exact locations for specific demand sides and capacity reductions are not available in the demand side proposals.) The point values were determined by PTI Siemens and then integrated into the Other Factors analysis, including the updated numbers regarding reliability for demand side projects.

PTI Siemens has submitted a revised summary report of its analysis, which is appended to this report. The PTI Siemens report has not been modified since it released on April 23, 2007.

4.6 Portfolio analysis

4.6.1 Objectives

While the assessment of individual projects helped LEI identify high performing, value-creating individual projects, LEI's ultimate objective was to attempt to build a portfolio of projects that would diversify the project execution risk and maximize net benefits for Connecticut ratepayers. Assessing whether or not portfolios did indeed produce net benefits that exceeded those of individual projects was one of our key tasks during the portfolio analysis.

There were several reasons behind our hypothesis that a portfolio of different projects would create more benefits for Connecticut ratepayers than just one project. First, the Needs Assessment concluded that FMCCs, as we outlined above in Section 3, come from different product markets and that FMCCs can thus be minimized by a combination of different kinds of technologies. The Needs Assessment concluded that Connecticut needed at least 600 MW in the short term, starting in 2007. Different types of projects can have different impacts on those markets. For example, a baseload generation plant will have a large impact on both the energy and the capacity market, but will take several years to come on-line thus they are unable to address near term capacity needs. On the other hand, energy efficiency projects also can have a significant impact on the capacity market (by reducing peak demand) and within a portfolio of projects can also contribute to reducing energy prices. In addition, energy efficiency projects can usually come on-line very quickly, within a year or so. Demand response projects and peaking plants also impact the FCM, and typically can be developed and put into commercial operation more quickly than conventional baseload generation. Moreover, the latter (peakers) tend to be most effective at addressing the specific needs of the Locational Forward Reserve Market, given their characteristics and the quick response time required for resources providing operating reserve service. A portfolio of different types of technologies is likely to offer more benefits to Connecticut ratepayers than can be provided by a single project, given the different strengths of various projects and the potential for complementarity between projects.

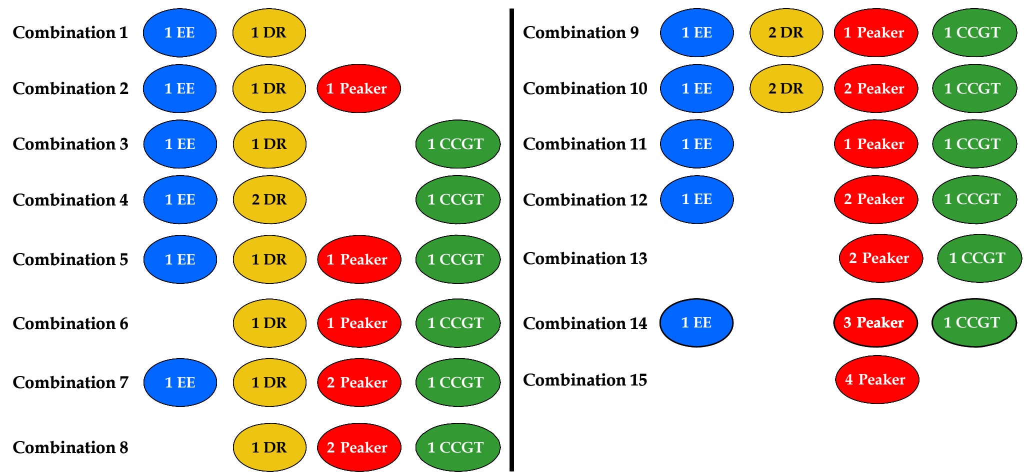
Second, having a portfolio of different projects also decreases the project execution risk for the entire portfolio. While LEI and its subcontractors have carefully analyzed bidders' credentials and each project's execution risk, developing large scale sophisticated projects is a complicated endeavor and a variety of factors can cause delays. If only one project is selected and that project is delayed for any number of reasons, Connecticut ratepayers would be exposed to substantially higher market costs, and would have foregone the benefits of the desperately needed capacity. Conversely, if a portfolio of different projects is selected, even if one project is delayed, other projects are likely to come on-line as planned, minimizing the impact to Connecticut ratepayers.

Third, having a portfolio of different projects also helps to contribute to increased diversification of resources that Connecticut relies on for its electricity. While generation projects are needed to meet Connecticut's capacity requirements, demand side projects such as energy efficiency projects and demand response projects reduce overall electricity demand and have positive environmental and siting attributes.

4.6.2 Methodology

Once the analysis of the individual projects was completed, LEI assessed portfolios comprised of more than 30 possible combinations of the best performing projects from the individual project analysis. The best performing projects were those with the highest level of average net benefits (mainly in terms of $/kW in order to allow for direct comparison of different-sized projects), those projects with acceptable levels of project execution risk, those that were considered to be both deliverable within the state of Connecticut and likely to qualify for the ISO-NE capacity market, and those projects with high scores in the Other Factors analysis. The figure below illustrates how we methodically created the combinations of projects for the portfolio analysis.

Figure 11. Portfolio mix combination



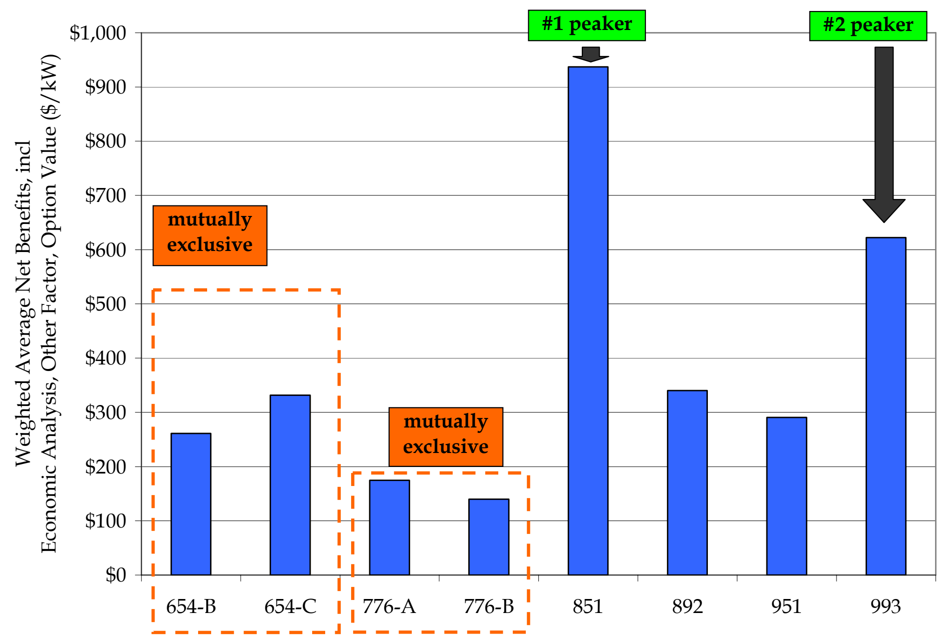
Note: There were 15 different combinations for the portfolio mix. However we ran more than 30 actual portfolio runs because we tested with both CCGT projects alternatively in some of the portfolios, we also tested different projects in the 2 peaker and 3 peaker combinations and 2 demand response combinations.

Because of the substantial energy benefits created by CCGTs, it was apparent that the final selected portfolio needed to have a baseload component. A baseload sub-portfolio was therefore created by combining the best CCGT (Project 409) and the energy efficiency project (Project 358). Different combinations of demand response and peaking projects were then tested on top of this baseload sub-portfolio in a methodical order. After the best performing portfolios were identified, they were further stress-tested using a different baseload plant (Project 146), and again using different configurations of the peaking and demand response components. We also tested removing the baseload projects altogether to ensure that they were creating net benefits for ratepayers.

In this way, LEI analyzed more than 30 different possible portfolios, testing whether or not the net benefits of adding different projects together were additive, duplicative, or neutral. The rationale behind this analysis is that the portfolio could result in projected benefits that are different than the arithmetic sum of the estimated benefits of the individual projects. Interactions between selected baseload, peaking, and demand side resources can jointly produce economic benefits that exceed the aggregate sum of each project's benefits individually if the projects are complementary. On the other hand, it is also possible that a portfolio can result in smaller economic benefits than the sum of the impacts of each individual project. This can occur in cases where projects are duplicative and therefore do not each produce incremental benefits. Such a result can occur when we reach diminishing returns with respect to the markets: the market price may reach a level from which it cannot easily move and therefore additional capacity does not produce any impact and simply raises the cost basis of the portfolio.

To illustrate how this process works, we highlight below the analytical process used to determine which peakers should be included in the portfolios. (The same approach and logic was applied to other technology classes.) In order to compare peakers of different sizes, the weighted average net benefits in $/kW terms (including Economic Analysis, Other Factor, and Option Value) was used. It is important to keep in mind that Project 654-B and Project 654-C were mutually exclusive and Project 776-A and Project 776-B were mutually exclusive, so only one could be chosen from each set. As can be seen from the figure below, Project 851 scored the highest weighted average net benefits, followed by Project 993, and then Project 892. Thus, if only one peaker was included in a portfolio combination, it would naturally be Project 851. If two peakers were included in a portfolio both Project 851 and Project 993 would be selected.

Figure 12. Illustration of selection process for top peakers



5 Selection of winning bidders

Section 12(i) of the EIA lays out the criteria by which the DPUC should judge the proposals. The DPUC should approve a contract if it determines that it will (1) result in the lowest reasonable cost of such products and services; (2) increase reliability; and (3) minimize FMCCs to the state of Connecticut over the life of the contract. In addition, Section 12(g) of the EIA provides some additional priorities that the DPUC should also try to factor into its selection of winning contracts. Section 12(g) states that the DPUC should give preference to proposals that result in the greatest aggregate reduction of FMCCs, make efficient use of existing sites and supply infrastructure, and serve the long term interest of ratepayers. The bid evaluation process was designed with these objectives in mind, as discussed in Section 4.1.

The winning portfolio meets all of these requirements as LEI will detail in the subsections below. The first subsection presents the performance of individual projects. The best of these projects were then aggregated into different portfolios to test whether combining different projects together created larger net benefits for Connecticut ratepayers. The portfolio analysis, summarized in Section 5.2, indicates that this was indeed the case. Finally, in Section 5.3, we describe the winning portfolio in more detail and in Section 5.5 we discuss the other benefits of the winning portfolio.

5.1 Performance of individual projects

LEI first analyzed individual projects within their technological categories – baseload generation, peaking generation, demand response projects, and energy efficiency projects – as discussed in the subsections below. When analyzed on an individual basis, projects were assessed by comparing their weighted average net benefits on a dollar per kW of installed capacity basis to be able to effectively compare projects of different sizes and to be able to compare across technological categories. The Appendix (see Section 6.3) provides more detailed bid evaluation results for each of these projects.

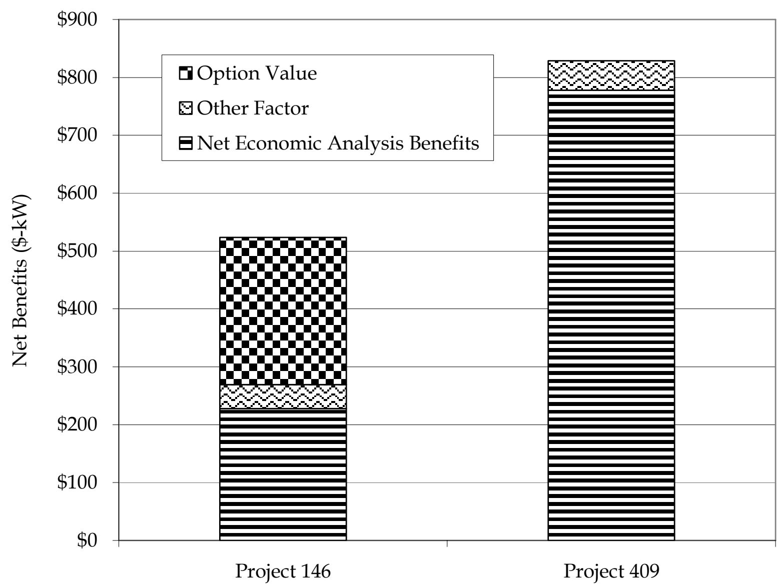
5.1.1 Baseload generation

We received two conforming Financial Bids for baseload generation. In general, new CCGTs create significant net benefits for the state of Connecticut because they displace inefficient and polluting power plants in the supply curve, effectively decreasing the cost of power production and the amount of total emissions produced. Lower energy prices indirectly also affect the LFRM by reducing the opportunity costs of participating in the LFRM and increasing competitive supply. This can lead to declining auction clearing prices in LFRM. In addition, baseload generation tends be large in size, and will therefore have a high likelihood of shifting the supply curve in the capacity market.

Project 409 strongly outperformed Project 146 in the Economic Analysis: Project 146 on a weighted average basis created $228/kW (or $138 million) in projected net benefits while Project 409 created $778/kW (or $476 million) in projected net benefits before factoring in the value of the Call Option and Other Factors. A large part of this difference, given the nominally similar size of the Contract Quantities of the two CCGTs, was driven by the fact that Project 409 is a completely new project and Project 146 is repowering of an existing facility, therefore the net physical capacity increase in the market attributed to Project 146 is substantially smaller than the overall size of the project.

Although Project 409 is supposed to come online a little later than Project 146, the foregone benefits from the capacity market are small and are offset by the fact that Project 409 contributes much more incremental physical capacity to the market. The impact that the two projects have in terms of economic net benefits is thus very different, as is evidenced in the graphic below. Project 146 offered the Call Option for the entire capacity of its project. While the Call Option in and of itself was considered valuable – its weighted average value discounted to 2007 terms was approximately $150 million – the value of the Call Option was not enough to offset the higher net economic benefits of Project 409, as illustrated in the graphic below.

Figure 13. Comparison of economic results of bids for baseload generation, based on the weighted average of all nine scenarios ($/kW of average annual Contract Quantity)



NRG in its Written Exceptions submitted on April 26, 2007 states that the Department should have analyzed their Project 146 assuming that the Montville 6 unit had retired and thus should have incorporated the full benefits for Project 146. This is problematic for several reasons. First, LEI analyzed all projects and portfolios against the same baseline. Thus, if we had analyzed Project 146 (and any portfolio containing Project 146) against a baseline without the Montville 6 unit, we would have had to analyze the other projects against that same baseline to have an "apples to apples" comparison.

However, our baseline was fixed based on publicly available information. NRG has not publicly announced to date that its Montville 6 unit would be retiring, and it certainly had not done so by December 13, 2006, the date at which bidders submitted their Financial Bids and the date at which LEI assumptions for the bid evaluation were fixed. Consistent with communication to bidders prior to Financial Bid submission, LEI assumed that retirements would not occur in the short term (as stated in the RFP) unless there was a publicly available retirement application by a generator pending before ISO-NE or there were public announcements about retirement intentions in the trade press. In the longer term, retirements were based on projected economics – whether or not the facility would be able to recover its fixed costs over a three year period. Based on our analysis, the Montville 6 unit was indeed able to recover its fixed costs through the Forward Capacity Market over the modeling time horizon. Moreover, given that the Montville 6 unit is only 36 years old, it does not seem unrealistic to assume that it could continue to operate for another 15 years. While there could be environmental regulations in the future that require additional capital investments, such speculative capital outlays were beyond the scope of the modeling.

Given that we could not rationalize retiring Montville 6 in our baseline analysis, and that the proposed Project 146 was on the location of Montville 6, it seemed only economically rational to analyze the incremental benefits accruing to the system from the addition of the new facility. Indeed, had we analyzed the full quantity of Project 146, we would have essentially been "double counting" about 400 MW of capacity, whose benefits would never have been realized for Connecticut ratepayers.

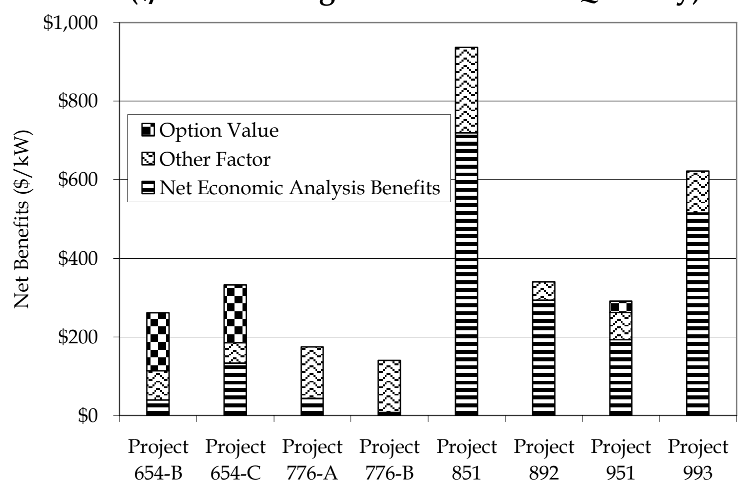
In addition, Project 409 also had numerous other strengths that position it as a stronger project as compared to Project 146. Project 409 was appraised with a lower risk in terms of interconnection, deliverability and risk for qualifying for the Forward Capacity Market. Project 409 already possesses a completed System Impact Study from ISO-NE, eliminating the risk of delay for this part of project development. In contrast, Project 146 is still in the interconnection queue and is likely to be constrained by East-West flows in Connecticut until that part of the transmission system is upgraded. Based on the transmission analysis conducted by PTI Siemens, Project 409 even under the most stringent assumptions, is likely to be deliverable at its full capacity level (inclusive of the incremental duct firing) within the state of Connecticut and is likely to qualify for the ISO-NE Forward Capacity Market based on currently known parameters. In contrast, Project 146 could have difficulties being dispatched at its full capacity under stringent transmission assumptions and this therefore creates some perceived risk regarding its qualification for the ISO-NE Forward Capacity Market based on currently available information. In terms of project execution risk, there was a greater risk for Project 146 because a unit with an existing Reliability Must Run contract had to be taken off-line for six months prior to commercial operation of the new CCGT to be reconfigured to connect with the new CCGT. The bidder could provide no documentation in response to our questions about whether or not ISO-NE would allow this, given that the unit was required for reliability purposes. Finally, Project 409 would create greater energy benefits due to the fact that it is more efficient (with a lower heat rate in its proposal and a warranted higher availability target) than Project 146, which will benefit Connecticut ratepayers in terms of potentially lower energy prices.

However, given that the portfolio impact of the two CCGTs could be different, LEI tested a large number of different portfolios using each of the CCGTs to see which project would perform better. Project 409 consistently performed better across the portfolio combinations.

5.1.2 Peaking capacity

There were stark differences among the peaking proposals, driven by size differences (peakers ranged from 70 MW to almost 300 MW), efficiency (heat rates ranged from 10.31 to 12.5 MMBtu/MWh for shortlisted generation projects), and proposed contract pricing (across the conforming peaking projects, proposed gross contract costs ranged from $642 per kW to $2,303 per kW[25]). Size was a particularly important issue in terms of calculating energy benefits as the smaller peakers produced statistically insignificant energy price changes; as such, projected energy benefits were negligible.[26] Our selection of the top peaking projects was based on net benefits on the basis of $/kW terms. Project 851 was clearly the best peaker with weighted average net benefits of $720/kW, with Project 993 being the second best peaking project with weighted average net benefits of $515/kW. While several peaking projects offered the Call Option, the value of that Call Option was never enough to offset those projects' performance compared to Projects 851 and 993. Project 851's value was driven by its very low contract costs, while Project 993's value was driven by the size of the benefits it was likely to produce due to its relatively high efficiency as compared to its proposed contract costs.

Figure 14. Comparison of economic results of bids for peaking projects based on the weighted average of all nine scenarios ($/kW of average annual Contract Quantity)



5.1.3 Demand Response projects

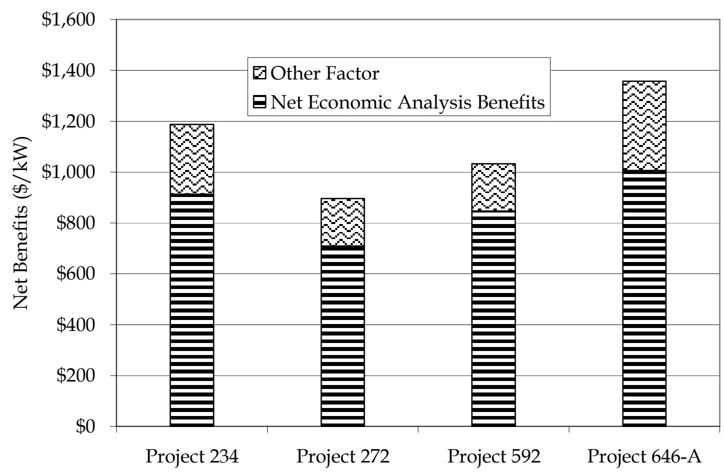
LEI modeled demand response projects as capacity resources consistent with ISO-NE's current draft Market Rules, and therefore these projects contribute to price reductions in the FCM. Because of their relative size and the style of participation in the market, they do not impact the

25 It is based on a discount rate of 9.8%.

26 A small peaker had no energy price impacts across all scenarios and all years, while a big peaker had some limited energy price impacts in Scenario 8 (3 years) and Scenario 9 (1 year). Please refer to Section 7 for more detailed discussion about this issue.

energy market in a significant way. Nor can most demand response projects participate in LFRM under the current market rules (the exception is demand response projects that qualify as asset-related demand). As a result, benefits for demand response projects come primarily from the capacity market. Project 646-A was clearly the best demand response project in terms of net economic benefits with a weighted average net benefit of $1,006/kW. It was also the best demand response project after factoring in Other Factors. Project 234 was the second best demand response project, with a weighted average net benefit of $913/kW. The incorporation of additional Other Factor points for reliability, as detailed in PTI Siemens' revised report appended to this report, did not change the order of the top two projects.

Figure 15. Comparison of economic results bids of demand response projects based on weighted average of all nine scenarios ($/kW of average annual Contract Quantity)



5.1.4 Energy efficiency projects

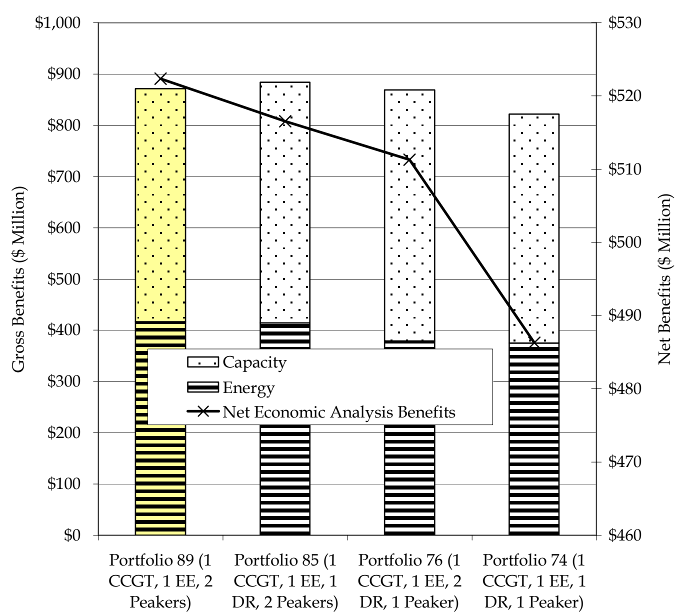
Only one energy efficiency project was shortlisted. Similar to the demand response projects, LEI modeled this energy efficiency project as a capacity resource consistent with ISO-NE's current draft Market Rules for the FCM, and therefore this project contributes to price reductions in the FCM, as well as a reduction in Connecticut load share because of the peak demand reductions. In addition, within a portfolio of other generation resources of a certain scale, this energy efficiency project produces some incremental value (although on a standalone basis, it does not impact energy prices in a statistically significant manner because of its relative size). The weighted average net benefits for Project 358 on a standalone basis totaled $-144/kW (or $-1 million) before factoring in quantity impacts (e.g., quantity-based energy savings due to the reductions in load) and Other Factors. After factoring in quantity impacts, the weighted average net benefits for Project 358 on a standalone basis totaled $2,680/kW (or $12 million) before factoring in Other Factors. After factoring in Other Factors and the quantity impact, Project 358's net benefits on a weighted average basis totaled $8,102/kW (or $36 million). Given the substantial potential benefits of the energy efficiency project after factoring in quantity impacts, LEI decided to test the energy efficiency project in a variety of portfolios to assess its interaction with other projects.

5.2 Identification of winning portfolio

As discussed in Section 4.6.2, LEI took the best performing projects from each category and created more than 30 portfolios to identify if a combination of projects created more value for Connecticut ratepayers and, if so, which portfolio was most attractive. As compared to the analysis of individual projects, at this point in the analysis, LEI considered both the dollar million net benefits (maximizing total net benefits accruing to Connecticut ratepayers) as well as the net benefits per kW of new or incremental capacity (measuring the average benefit created by each kW). The appendix provides results for all portfolios analyzed.

Portfolio 89 resulted in the largest aggregate net benefits in dollar million terms to ratepayers over the 15 year time horizon. The Economic Analysis concluded that Portfolio 89 created an average of $522 million in net benefits (using the weighted average of the nine scenarios), or $793/kW.[27] A detailed buildup of Net Benefits produced by Portfolio 89 can be found in the box below. The net benefits for Portfolio 89 ranged from $-79 million to $1,770 million across the nine scenarios. Portfolio 89 obtained a score of 9.5 out of 15 on Other Factors, which added an additional $29 million to its Economic Analysis score to total expected net benefit of $552 million or $837/kW. For comparative purposes, we show the top four portfolios' gross and net economic benefit in the figure below; note that Portfolio 89 is represented by the first bar to the left. (For a simplified version of this chart, see Figure 1 on page 6.)

Figure 16. Comparison of top portfolios based on weighted average of gross benefits and net benefits across all nine scenarios ($ million)



Note: Gross benefits do not factor in costs for the capacity; Net Benefits equal Gross Benefits minus Contract Costs

27 The Net Benefits of Portfolio 89 is even larger if the quantity impact of the energy efficiency project is factored in: $535 million or $812/kW.

Detailed Buildup of Net Benefit for Portfolio 89

For each product market - energy, capacity, and LFRM - LEI calculated the cost to Connecticut load without any project and then subtract the cost to Connecticut load with Portfolio 89 to determine the portfolio's net benefits.

Energy benefit calculation:

The average cost of electricity in Connecticut without any project in 2011 under Scenario 2 was projected to be $76.37/MWh and the energy consumption in 2011 under Scenario 2 was projected to be 36,605,000 MWh. Then the cost of energy to Connecticut ratepayers in 2011 under Scenario 2 was projected to be $76.37/MWh * 36,605,000 MWh = $2,795.7 million. With Portfolio 89, the energy price in 2011 under Scenario 2 was projected to be $74.70/MWh. Therefore the total cost of energy to load would be equal to $74.70/MWh * 36,605,000 = $2,734.5. million dollars. Thus, the energy benefits that Connecticut ratepayers received as a result of this portfolio was equal to what they would have paid without the project minus what they would anticipate paying with the project, or $2,795.7 million - $2,734.5 million = $61.2 million in 2011 under Scenario 2. This calculation was applied in each year of the modeling horizon (2007-2025) and across nine scenarios. In summary, the weighted average cost of electricity in Connecticut without any project between 2007 and 2025 across nine scenarios was $89.51/MWh and that the annual energy consumption between 2007 and 2025 across nine scenarios was 38,513,177 MWh. The average cost of electricity in Connecticut with Portfolio 89 between 2007 and 2025 across nine scenarios was $88.10/MWh and the energy consumption doesn't change with or without Portfolio 89 (assuming no "quantity effect" from Energy Efficiency). The NPV of the weighted average energy benefits between 2007 and 2025 across nine scenarios to Connecticut ratepayers due to selecting Portfolio 89 is expected to total $417 million (or $632/kW).

Capacity benefit calculation:

The capacity benefit calculation is essentially the same though there are some nuances to the Forward Capacity Market that are not addressed in this simplified example. The Forward Capacity Market clearing price in 2011 under Scenario 2 was projected to be $5.79/kW-month without any project and $5.23/kW-month with Portfolio 89. The benefit to Connecticut ratepayers would be the difference in the two clearing prices; $5.79/kW-month - $5.23/kW-month (before netting of PER of $0.03/kW-month) multiplied by the Connecticut peak load share of the New England ICR, which was 26.59% without any project and 26.57% with Portfolio 89 of 33,659 MW. The capacity cost without any project in 2011 under Scenario 2 was equal to ($5.79/kW-month – $0.03/kW-month) * 1,000 * 12 months * 26.59% * 33,659 MW = $619.1 million. The capacity cost with Portfolio 89 in 2011 under Scenario 2 was equal to ($5.23/kW-month – $0.03/kW-month) * 1,000 * 12 months * 26.59% * 33,659 MW = $557.8 million. The capacity benefits of Portfolio 89 in 2011 under Scenario 2 were equal to $608.3 million - $557.6 million = $61.3 million. This calculation was applied in each year of the modeling horizon (2007-2025) and across nine scenarios. The NPV of the weighted average capacity benefits between 2007 and 2025 across nine scenarios to Connecticut ratepayers due to selecting Portfolio 89 is expected to be $455 million (or $691/kW).

LFRM benefit calculation

LFRM benefit calculation is more complicated as it takes into account the relative contributions of each of the four LFRM zones (Boston, Southwest Connecticut (which is nested in the Connecticut zone), Connecticut, and rest of New England) to the total cost of providing operating reserves. That said, the benefit to Connecticut ratepayers is still the cost of purchasing operating reserves without a project, less the cost of purchasing those reserves with the project. The cost of reserves for the state of Connecticut (including both SWCT and Connecticut zones) in 2011 under Scenario 2 without a project was $23.4 million, but Portfolio 89 increased that cost to $23.5 million. Then the benefit to Connecticut ratepayers resulting from that project is -$0.1 million in 2011 under Scenario 2. The NPV of the weighted average LFRM benefits between 2007 and 2025 across nine scenarios to Connecticut ratepayers due to selecting Portfolio 89 is expected to be -$6 million (or -$10/kW).

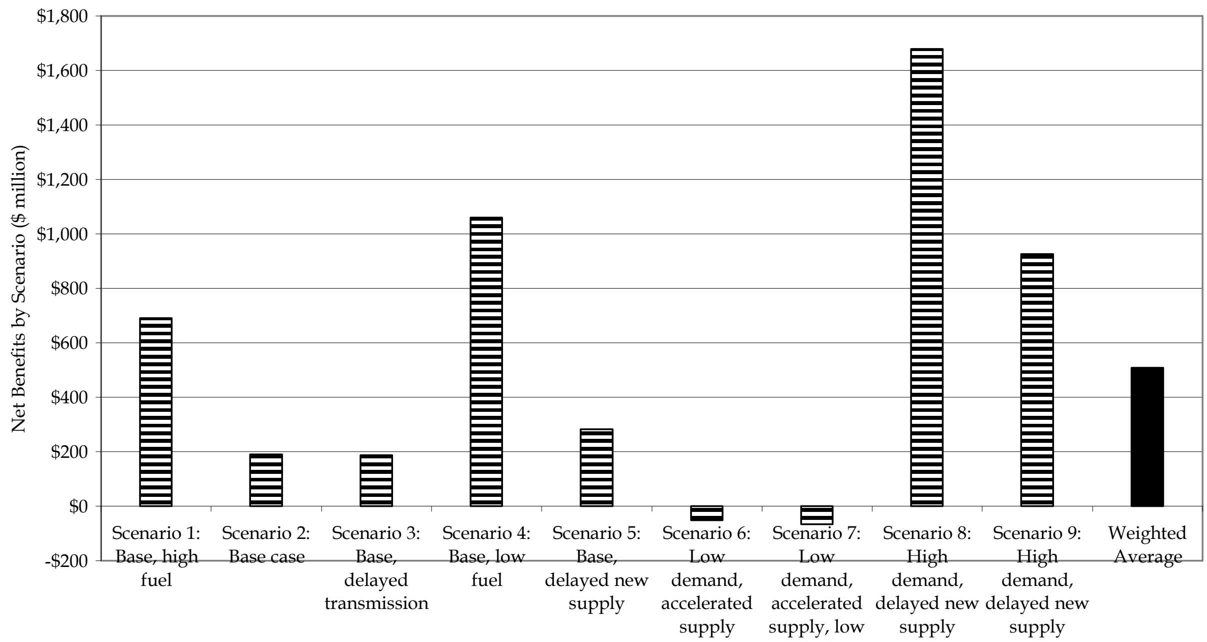
Contract cost calculation

Portfolio 89's total contract quantity is 787 MW and has the weighted contracted to settle against the FCM market clearing price for $12.10/kW-month in 2011 under Scenario 2. The market clearing price in the FCM for 2011 was $5.23/kW-month. Thus, the payments to Portfolio 89 (cost of the project to Connecticut ratepayers) in 2011 were the difference between the project contract price and the FCM clearing price, ($12.10/kW-month - $5.23/kW-month) * 787,000 kW * 12 months per year = $64.9 million. The same calculation was applied to LFRM settlement. The NPV of the combined weighted average contract costs between 2007 and 2025 across nine scenarios to Connecticut ratepayers due to selecting Portfolio 89 is expected to be $343 million (or $520/kW).

The NPV of weighted average between 2007 and 2025 **net benefit** to Connecticut ratepayers for Portfolio 89 then is the sum of the benefits that the project produced in each of the three product markets minus its settled contract costs: $417 million (energy benefit) + $455 million (capacity benefit) + (-$6) million (LFRM benefit) - $343 million (contract cost) = $522 million in net benefits.

Portfolio 89 also offers significant downside protection to Connecticut ratepayers. Of the nine scenarios analyzed, Portfolio 89 creates negative net benefits in only two of those scenarios – Scenarios 6 and 7. These two scenarios assume that there will be an economic downturn and that fuel prices will decrease dramatically, driving market prices downward for the energy market and FCM. The value added of this portfolio's capacity is not large enough to offset contract costs for many years under these market conditions. Given the low probability of this market outcome, these two scenarios are not weighted very heavily in the total average weighting – being granted only 10% each. Importantly, Portfolio 89 performs well in all of the more likely scenarios and performs very well in the scenarios that Connecticut policymakers are most concerned about (e.g., those scenarios that simulate conditions which result in high prices, such as delayed new supply as replicated in Scenarios 5, 8, and 9, and high fuel prices, as modeled in Scenarios 1 and 8).

Figure 17. Net Economic Analysis Benefits for Portfolio 89 by scenario ($ million)



Portfolio 85 was the runner up portfolio in terms of overall net benefit, with the fourth largest net benefit in dollar million terms. Portfolio 85 had an additional demand response project as compared to Portfolio 89. However, the benefits of that additional project did not outweigh its incremental costs: the weighted average net benefits of portfolio 85 totaled $517 million as compared to Portfolio 89's $522 million, a $5 million difference. Some stakeholders argued that the DPUC should choose Portfolio 85 for policy reasons. LEI, however, cannot rationalize this argument given the results of the Economic Analysis and the requirements of the EIA to minimize FMCCs and select projects that are least cost given the benefits that they produce. The Economic Analysis leads us to conclude that portfolio 89 provides the most ratepayer benefits in the most cost effective manner.

Portfolio 74 was one of the next highest portfolios in terms of overall net benefit. Portfolio 74 contains a demand response project instead of Portfolio 89's second peaker. The demand response project (Project 646-A) performed better than the peaker on an individual basis, however, within a portfolio the peaker is able to produce larger energy benefits due to the presence of the CCGT. Therefore, Portfolio 74's weighted average net benefits at $486 million or $774/kW were 7.4% lower than those of Portfolio 89. Portfolio 76, the biggest portfolio among the finalists, contained two demand response projects as well as a peaker. Although it did not top Project 89's projected net benefits, Project 76 did perform better than Portfolio 74 with weighted average net benefits of $511 million or $715/kW but still could not top Portfolio 89's net benefits.

The benefits for Portfolio 89 are largely driven by benefits realized through reduced energy prices and reduced capacity prices. On a weighted average basis, Portfolio 89 creates $417 million in benefits from the energy market (without counting the quantity impact) and $455 million in benefits from the capacity market. Like many of the portfolios we analyzed, Portfolio 89 does not create any positive impact in the locational forward reserve market, which we discuss in more detail in Section 5.3.

In our opinion, Portfolio 89 meets all of the requirements of the EIA. Given that Portfolio 89 produced the highest net benefits (or in other words, created the biggest benefits for the least cost) in our competitive RFP, LEI can conclude that Portfolio 89 would be procured at the least cost possible, and that it minimized FMCCs for Connecticut ratepayers, and that it is in the long term interest of ratepayers. Portfolio 89 also contributes to system reliability, as attested to by Siemens PTI's analysis of the transmission system and our simulation modeling of system stress events. For example, this incremental capacity, and specifically the contractual obligation to include oil storage and oil fuel burn capability, can help reduce the number and duration of electricity supply interruptions (blackouts) in the case of severe gas shortages. Using a simulation of a gas shortage situation that reduces gas-fired capacity in New England by about 50% during the peak demand period, LEI tested the implications for supply interruptions (blackouts), using ISO-NE's 90/10 demand forecast. Portfolio 89 reduced the duration of potential electricity supply interruptions by nine hours during a simulated peak demand week in 2011. At a conservative estimate, the cost savings for the local economy for reducing the duration of or averting such interruptions can range from $1,000 to $3,000 per MW of load per hour. Given Connecticut's peak load and the nine hours of averted supply interruptions noted above, Portfolio 89 could create savings of $76 to $229 million in the event of a severe gas shortage.

Portfolio 89 also made use of existing sites, as required under Section 12(g) of the EIA: one of the projects is a demand side project that does not require siting; another project is on an existing site that will require no additional infrastructure; and the last two projects are on existing industrial sites that have some required infrastructure.

5.3 Winning portfolio in light of Investment Needs analysis

The Investment Needs analysis issued by London Economics in the fall of 2006 and referenced in Section 3 of this report stated that Connecticut required approximately 600 MW of peaking capacity in the short term in order to fill the supply-demand 'gap' in the LFRM market and in the longer term, could need of up to 1,700 MW to meet the Local Sourcing Requirement of the FCM. Based on current set of projections for supply-demand dynamics for LFRM and FCM, this MW-based prognosis still holds true.

However, based on the bid evaluation (namely the bid prices received in the RFP and the forecast range of market prices), it is not cost-effective for the Connecticut ratepayers to procure that full peaking requirement at this time. Moreover, the LFRM costs represent only a small portion of total congestion charges (FMCCs) paid by Connecticut ratepayers. Therefore, Connecticut ratepayers can take advantage of much larger benefits from reducing the costs of capacity in the FCM and or energy purchases than the costs of LFRM. In addition, the unique nature of the design of the LFRM means that it is difficult for any project to create strong positive net benefits in the LFRM.

In the early years of our analysis, the minimal nature of the LFRM benefit is largely due to the vertical demand curve of that market as represented by the fixed locational forward reserve requirement for which ISO-NE procures: Connecticut must have more capacity than the procurement amount that ISO-NE seeks in order to move the LFRM prices away from the \$14/kW-month cap. Since none of the individual projects (alone or in combination) are large enough to exceed the fixed locational forward reserve requirement (LFRR), any peaking facility coming on-line before 2010 actually creates "dis-benefits" in the LFRM because it creates net additional costs for Connecticut ratepayers. These "dis-benefits" are significant and with the discounting effect, projected net benefits for LFRM in future years cannot be overcome these early costs (for any peaking project coming on-line before 2010).

After 2010, there is still little impact on the LFRM price with increasing LFRM capacity, because of the netting of FCM clearing prices from the auction clearing prices in LFRM. Furthermore, based on the relationship observed in the forward reserve market historically (in the recent Locational Forward Reserve auctions (LFRAs) and in previous system-wide FRAs), the LFRM premium (which is the LFRM price less the capacity price) does not vary dramatically. This is not surprising if one considers the opportunity costs that dictate the premium that a LFRM supplier seeks in order to agree to provide forward reserves. A LFRM supplier will want some positive amount in order to provide the service, but it will not need to recoup all his fixed costs from the LFRM given the revenues it can earn in the capacity market. Indeed, LFRM suppliers are likely building their bid primarily around their expected opportunity costs, which are a function of their foregone energy revenues and potential penalties – both are likely to be minimal. According to our econometric model that tracks historical bidding in the FRAs[28], an increase in LFRM capacity in Connecticut by 100 MW usually only decreases the LFRM premium by \$0.06/kW per month.[29] While Connecticut does need about 600 MW of capacity to

28 We expect that the opportunity costs for participating in the LFRM are fairly constant across locational areas and therefore it is sensible to look at historical bidding patterns in both the FRAs and the first LFRA.

29 Please see Section 7.3 of the Appendix for a more detailed explanation of how LEI calculated the LFRM premium.

fully meet ISO-NE's LFRR, and substantial peaking capacity was bid into the RFP, the potential benefits of that peaking capacity did not outweigh its costs.

We tested this hypothesis, however, by running a portfolio of all the conforming shortlisted peaking capacity (Portfolio 114) to see what impact this would have on the markets and whether such a portfolio could be rationalized. By adding 628 MW of peaking capacity to Connecticut, $44 million in gross benefits from the energy market are projected; with an additional $249 million of gross benefits from the capacity market; and dis-benefits of $30 million for LFRM (due to reasons discussed above). After factoring in the costs, this portfolio created $20 million (or $34/kW) in projected net benefits for Connecticut ratepayers on a weighted average basis across nine scenarios, which is far below the average net benefits projected for Portfolio 89.

Because LEI's analysis was conducted by analyzing the costs and the benefits to Connecticut ratepayers, as required by the EIA, we cannot rationalize forfeiting possible ratepayer benefits to procure the amount of peaking capacity specified in the Investment Needs analysis. Instead, LEI feels confident that the selected portfolio will reduce total costs to load, as anticipated in the bid evaluation analysis, which will ultimately benefit ratepayers in the long run.

5.4 Description of winning portfolio

Portfolio 89 contains four projects and totals 787 MW at its maximum capacity. The four winning projects are:

- Project 409 (a Combined Cycle Gas Turbine with 620 MW in Middletown, Connecticut);
- Project 851 (a 66 MW oil-fired peaker located in Stamford, Connecticut);
- Project 993 (a 96 MW efficient peaking plant in Waterbury, Connecticut); and
- Project 358 (a state-wide 5 MW energy efficiency program).

While the previous section detailed the strengths of Portfolio 89, it is also important to understand the comparative advantage of each individual project in this portfolio as compared to other proposals received in this RFP. The projects that comprise Portfolio 89 were the highest performing projects in their technological class on a stand-alone basis and, as discussed above, resulted in the best portfolio among all other portfolios examined.

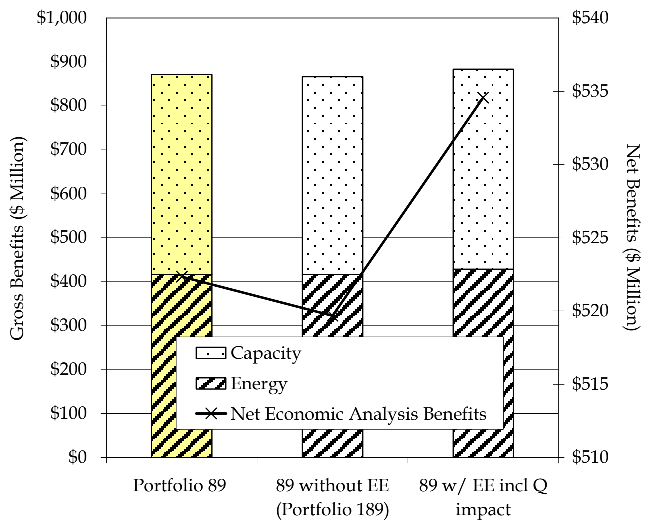
As stated above, Project 409 performed better in terms of the Economic Analysis than the other possible baseload plant, creating weighted average net benefits of $778/kW (or $476 million) as compared to Project 146's $228/kW (or $138 million). Other Factors analysis contributed an additional $31 million in value to Project 409's total score, resulting in weighted average net benefits of $829/kW (or $507 million). Project 409 was also viewed to be less risky than the other baseload plant in terms of interconnection risk and deliverability risk, as discussed in detail above.

Project 851 was the strongest peaking project due largely to its lower than average contract costs. As such, it created weighted average net benefits of $720/kW (or $48 million) in the pure Economic Analysis. Project 993 was the second strongest peaking project, due to its costs relative to its benefit in the FCM; its weighted average net benefits were $515/kW (or $49 million). Moreover, Project 993 had the second lowest heat rate of the short-listed peaking projects, which generated additional energy market benefits once the project was incorporated into a portfolio containing other baseload resources. Net benefits of other peaking plants ranged from $8/kW to $294/kW, far below those of Project 851 and Project 993. Other Factors analysis contributed an additional $14 million in value to Project 851's total score and an additional $10 million to Project 993's total score. Project 851 already possesses an interconnection agreement with ISO-NE and faces little additional siting or permitting to come online as a permanent facility. As such, its project execution risk score was considered to be relatively low. Project 993 is in the ISO-NE interconnection queue but in its assessment of this project, PTI Siemens did not see a large risk for this project in terms of interconnection or qualification for the FCM.

It is important to point out that although two demand response projects performed better on a standalone basis than the best peaking plants (as measured by weighted average net benefits in $/kW terms), peaking plants performed better in the portfolios. This is due to several factors. First, on a stand-alone basis, most peaking plants could not significantly impact energy prices. In combination with a CCGT, however, peaking plants could create additional energy benefits. Second, peaking plants had the potential to create some benefits in all three of the ISO-NE markets which our analysis focused on – energy, capacity, and locational forward reserves - whereas demand response projects can generally only create capacity benefits (unless they are qualified to participate in LFRM). Third, the two peaking plants selected in the winning portfolio will provide a foundation for fast-start generating capacity, on which the market can build. While the Economic Analysis did not justify procurement of additional peaking projects to fully meet Connecticut's LFRM requirement, there is a benefit to initiating some level of new peaking build in the state. This benefit was not captured in the economic analysis, but is nevertheless, still valuable.

Project 358 was the only energy efficiency project that was included on the short list. On a stand alone basis, without factoring in the energy efficiency's quantity impact, the project's net benefits were slightly negative at $-144/kW (or $-1 million). However, Project 358 contributed to the total net benefits of Portfolio 89, as highlighted in the figure below. Without Project 358, Portfolio 89 created $520 million in net benefits, or $794/kW. With Project 358, Portfolio 89 created $522 million in net benefits, or $793/kW. Incorporating the quantity impact on the energy market from Project 358, Portfolio 89's weighted average net benefits rose higher, totaling $535 million or $812/kW. Thus, Project 358 clearly contributes value for Connecticut ratepayers within the context of Portfolio 89, as is illustrated on the graphic below.

Figure 18. Impact of Project 358 within Portfolio 89 based on the weighted average gross benefit by market and weighted average net benefit ($ million)



Note: Gross benefits do not factor in costs for the capacity; Net Benefits equal Gross Benefits minus contract costs

5.5 Other benefits of winning portfolio

While the previous sections have focused mainly on the economic benefits of Portfolio 89 and how Portfolio 89 achieves the requirements contained in the EIA, this subsection focuses on how Portfolio 89 also addresses some of Connecticut's other policy priorities.

Portfolio 89, with a new 620 MW CCGT and 5 MW of energy efficiency, helps to substantially reduce environmental emissions across New England. As compared to the baseline analysis, Portfolio 89 reduces NOx emissions by just over 520,000 tons, SO_2 emissions by almost 1.8 million tons, and CO_2 emissions by almost 1 billion tons over the 15 year time horizon.[30] This environmental reduction is largely accomplished by reducing peak demand, which is met in Connecticut by old, inefficient power plants, and by displacing the most inefficient generation with a new relatively more efficient and low polluting CCGT.[31] The figure below shows the year-on-year emission reductions from SO_2, NOx, and CO_2 for Portfolio 89.

As an illustration of how Portfolio 89 is able to reduce environmental emissions, we can look at one sample year. In 2011 of Scenario 2, the introduction of the portfolio into the New England system causes other capacity to reduce their output significantly. In Figure 19 below, we can see how several plants were forced to reduce their output and fuel consumption because of the

30 Note that this emission reduction is based on the weighted average of all nine scenarios. Over the nine scenarios, SO_2 emission reductions ranged from just over 1 million tons to just over 2 million tons reduction; NOx emission reductions ranged from almost 350,000 to 660,000 tons reduction; and CO_2 emission reductions ranged from 758 million to 1.1 billion tons reduction.

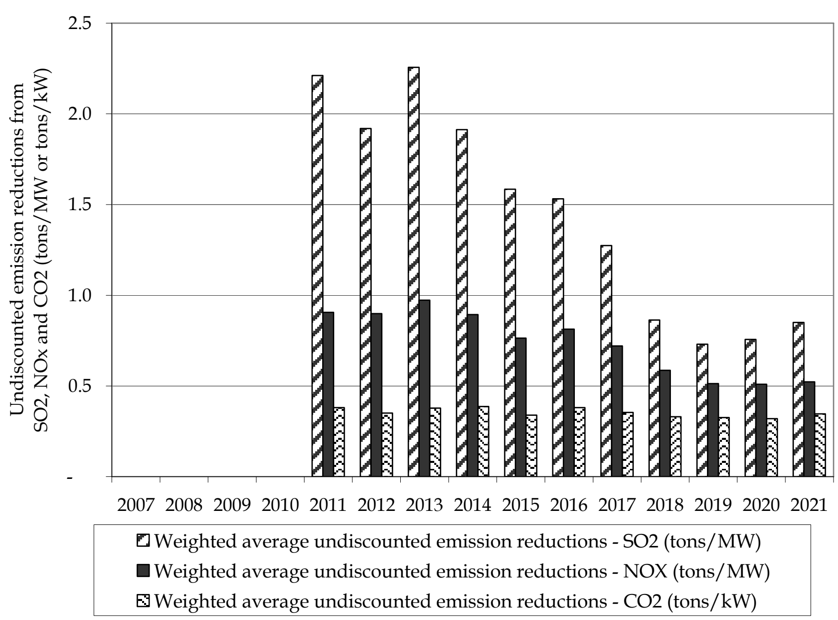
31 We have relied on the emissions rates provided by and attested to by the bidders in their Financial Bid submissions in determining these impacts.

redispatch caused by the introduction of Portfolio 89. This example shows that just among the 18 plants highlighted, that SO_2 emissions declined by 939 tons, NOx emissions decreased by 311 tons, and CO_2 emissions declined by nearly 700,000 tons. When this type of impact is measured across all the generating plants in the system, and added together over 15 years, it becomes quite clear how the introduction of Portfolio 89 can create such enormous environmental benefits.

Figure 19. Emission reduction created by the introduction of Portfolio 89 among the 18 most effected plants

Plant Name	Zone	output (GWh) in Base case	output (GWh) with 89	Primary fuel consumption (MMBtu) - baseline	Primary fuel consumption (MMBtu) with 89	Primary fuel consumption reduction (MMBtu)	SO2 emission reduction (tons)	NOx emission reduction (tons)	CO2 emission reduction (tons)
Milford	SC	1,952	1,645	13,834,850	11,653,650	2,181,200	0.84	9.55	129,885
LAKE ROAD 3	SR	796	662	5,716,150	4,752,850	963,300	0.37	4.09	57,351
LAKE ROAD 1	SR	751	614	5,395,050	4,412,750	982,300	0.37	4.18	58,483
LAKE ROAD 2	SR	692	562	4,972,300	4,037,500	934,800	0.36	3.97	55,655
DIGHTON POWER 1	SR	440	347	3,213,850	2,533,650	680,200	0.20	4.30	40,424
MILFORD POWER	SR	396	313	3,045,700	2,406,350	639,350	0.00	13.71	0
NEA BELLINGHAM_1	SR	257	195	2,070,050	1,568,450	501,600	0.00	24.20	0
NEA BELLINGHAM_2	SR	259	195	2,090,000	1,567,500	522,500	0.00	25.20	0
MASS POWER	MV	362	284	2,948,800	2,310,400	638,400	0.13	11.06	25,691
MANCHESTER 11/11A CC	SR	203	155	1,660,600	1,262,550	398,050	0.14	8.27	23,608
MANCHESTER 9/9A CC	SR	183	143	1,497,200	1,165,650	331,550	0.11	6.89	19,664
MANCHESTER 10/10A CC	SR	194	153	1,582,700	1,252,100	330,600	0.11	6.87	19,608
NEW HAVEN HARBOR	CT	356	260	3,621,400	2,644,800	976,600	129.02	67.62	79,046
CANAL 2	SR	308	245	3,184,400	2,530,800	653,600	360.05	45.58	56,007
CANAL 1	SR	333	273	3,442,800	2,819,600	623,200	343.30	43.46	53,402
MYSTIC 7	NB	131	81	1,421,200	879,700	541,500	103.29	24.42	37,513
OCEAN ST PWR GT3/GT4/ST2_TransCanada	SR	213	166	1,816,400	1,420,250	396,150	0.00	5.40	0
FORE RIVER-1	SR	2,761	2,654	18,722,600	17,996,800	725,800	0.29	2.43	43,133
Total		**10,589**	**8,946**	**80,236,050**	**67,215,350**	**13,020,700**	**939**	**311**	**699,471**

Figure 20. Weighted average undiscounted emission reductions from SO_2, NOx and CO_2 for Portfolio 89 (tons/MW for SO_2 and NOx; tons/kW for CO_2)



Portfolio 89 is also likely to enhance system reliability and potentially reduce the need for reliability must run contracts, as is discussed in the report summarizing the transmission analysis performed by PTI Siemens.

Finally, Portfolio 89 also reduces concerns about market power in the state of Connecticut. We tested the impact of this new capacity in Connecticut on the wholesale energy market using two different modeling approaches. First we analyzed the concentration of the market by calculating the Herfindahl-Hirschman Index (HHI)[32] concentration level of the ISO-NE day ahead energy market, an approach commonly applied in economics as a first check on market structure. A derivative of the HHI analysis is also required by FERC Order Nos. 592 and 642. We calculated a capacity-based HHI for the market using forecast 2011 data, which is when all four projects would be operational. Our results showed that the HHI without these projects would be in the range of 525 (based on the current ownership of supply resources), while the HHI with Portfolio 89 is estimated at 504. This analysis provides two important conclusions. First, the New England market is not concentrated, as the HHI score in both cases is below 1,000.[33] Second, the HHI actually decreases by more than 20 points by adding Portfolio 89, which indicates that the portfolio serves to de-concentrate the market. Although Connecticut load zone would not be defined as a distinct market under FERC guidelines given that it is part of a formal regional power market operated by an independent system operator, Portfolio 89 also de-concentrates the generation capacity in the Connecticut load zone[34].

The second way that we tested market power concerns was to analyze the abilities of generators in Connecticut to strategically increase hourly energy prices in the Connecticut zone by using a game theoretic simulation approach using LEI's proprietary strategic bidding model, ConjectureMod, as applied to the New England wholesale market. We relaxed the short-run marginal cost bidding assumption for the largest six market participants and re-ran the energy market model, PoolMod, using the ConjectureMod bidding algorithms with and without

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32 The HHI is an analytical approach that can be used to assess the current level of concentration in the market, achieved by adding the squared market shares of every market participant together.

33 The Department of Justice *Merger Guidelines* lay out three ranges of market power concentration: an unconcentrated post-transaction market, which is indicated by an HHI below 1,000; a moderately concentrated post-transaction market, which is indicated by an HHI ranging from 1,000 to 1,800; a highly concentrated post-transaction market, which is indicated by an HHI above 1,800. The level of HHIs is further supplemented by the change in HHIs to determine whether a transaction raises competitive market concerns. A change in HHI below 100 combined with a post-transaction HHI below 1,800 is acceptable. A change in HHI below 50 combined with a post-transaction HHI of above 1,800 is also acceptable.

34 Under commonly-accepted anti-trust guidelines for market definition, Connecticut would not be viewed a distinct geographical market once you apply a reasonable time dimension to the market definition and consider the level of integration with rest of New England (which is reflected in the prices). Anti-trust guidelines require that we define a market by reference to substitutes. In the context of electricity markets, the question to ask is whether a hypothetical monopolist controlling all generation in Connecticut can profitably sustain a small but significant increase in price over a one to two year period. Given the extent of transmission interconnection with New England vis-à-vis internal demand, import purchases are likely to discipline that hypothetical monopolist and therefore Connecticut is unlikely to be deemed a distinct market currently. However, as demand grows and the frequency and magnitude of the transmission constraints increase, the potential for competitive response is likely to diminish and Connecticut may move towards a distinct market classification.

Portfolio 89 under Scenario 2 (we tested Scenario 2 as that scenario represents the most likely market outcome). We continued to impose the other modeling assumptions, including the transmission limits between sub-regions within New England. We also isolated the Connecticut sub-region as a distinct zone for purposes of gaming (the transmission topology is one of the parameters that strategic players will consider in optimizing their bidding strategy in ConjectureMod). The large market participants were allowed to set their bids above marginal cost in such a way as to maximize their portfolio profits, given projected demand and other simulated system conditions. We found that forecasted market prices under these modeled conditions in the Connecticut load zone were actually lower after we brought online the projects in Portfolio 89. These four projects have no effective ability to be strategic and moreover have no incentive to raise market prices because their compensation is effectively fixed through the terms of the contract. In addition, these four projects increased overall market competition and reduced the potential for existing market participants to profitably raise prices. We found that over the 15 year modeling horizon, generators were ***less*** able to increase prices in Connecticut with Portfolio 89 than under the status quo. The presence of the projects in Portfolio 89 reduced forecasted market prices in the Connecticut zone in a non-trivial manner: the price reductions ranged from $1.16/MWh to $3.20/MWh. This market power dampening effect is effectively equal to another $378.8 million of benefits from the perspective of consumers.[35]

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35 This figure effectively represents the increase in consumer surplus due to reduction in producer surplus. It is calculated on the basis of the forecasted annual price difference over the 15-year forecast time horizon multiplied by annual electricity consumption level for Connecticut, and discounted back to 2007 terms.

6 Appendix A: Results of bid evaluation analysis by project and portfolio

6.1 Key to appendix graphics

CCGT – Baseload Combined Cycle Gas Turbine
EE – Energy Efficiency
DR – Demand Response
NB – Net Benefits (gross benefits minus costs)
OF – Other Factors
OV – Option Value

6.2 Portfolio results

Note that rankings at the bottom of the graphic are among all portfolios.
Note that $/kW figures are calculated using average contract quantity over the contract term

Portfolio Name	**Portfolio 61**	**Portfolio 62**	**Portfolio 63**	**Portfolio 64**	**Portfolio 65**	**Portfolio 66**	**Portfolio 67**	**Portfolio 68**
Projects	Portfolio A, D, I	Portfolio A, D, I, C	Portfolio A, D, O	Portfolio A, D, I, O	Portfolio A, D, I, O, Q	Portfolio A, D, I, C, O	Portfolio A, D, I, C, O, Q	Portfolio A, D, O, Q, M
Portfolio Mix	1 CCGT, 1 EE, 1 DR	1 CCGT, 1 EE, 2 DR	1 CCGT, 1 EE, 1 Peaker	1 CCGT, 1 EE, 1 DR, 1 Peaker	1 CCGT, 1 EE, 1 DR, 2 Peaker	1 CCGT, 1 EE, 2 DR, 1 Peaker	1 CCGT, 1 EE, 2 DR, 2 Peaker	1 CCGT, 1 EE, 3 Peaker
Portfolio Size (Total MW)	707	857	698	773	960	923	1110	972
Average Benefits - ENERGY ($/kW)	$ 390	$ 324	$ 399	$ 365	$ 310	$ 326	$ 279	$ 306
Average Benefits - ENERGY ($ million)	$ 222	$ 212	$ 226	$ 228	$ 241	$ 232	$ 242	$ 235
Average Benefits - CAPACITY ($/kW)	$ 351	$ 440	$ 336	$ 411	$ 343	$ 470	$ 477	$ 324
Average Benefits - CAPACITY ($ million)	$ 200	$ 289	$ 190	$ 256	$ 267	$ 334	$ 413	$ 249
Average Benefits - LFRM ($/kW)	$ (4)	$ (3)	$ (10)	$ (11)	$ (22)	$ (10)	$ (19)	$ (21)
Average Benefits - LFRM ($ million)	$ (2)	$ (2)	$ (6)	$ (7)	$ (17)	$ (7)	$ (17)	$ (16)
Average Benefits ($/kW)	$ 738	$ 761	$ 725	$ 765	$ 631	$ 786	$ 737	$ 609
Average Benefits ($million)	$ 420	$ 499	$ 410	$ 477	$ 491	$ 559	$ 638	$ 468
Average Costs ($/kW)	$ 490	$ 435	$ 473	$ 433	$ 438	$ 412	$ 434	$ 444
Average Costs ($ million)	$ 279	$ 285	$ 267	$ 270	$ 341	$ 293	$ 376	$ 341
Average Net Benefits (NB) ($/kW)	**$ 247**	**$ 326**	**$ 252**	**$ 332**	**$ 193**	**$ 374**	**$ 302**	**$ 165**
Average Net Benefits (NB) ($ million)	**$ 141**	**$ 214**	**$ 142**	**$ 207**	**$ 150**	**$ 266**	**$ 262**	**$ 127**
MAX of NB across scenarios ($MM)	$ 919	$ 1,030	$ 935	$ 1,086	$ 1,000	$ 1,080	$ 1,162	$ 1,019
MIN of NB across scenarios ($MM)	$ (307)	$ (198)	$ (176)	$ (174)	$ (247)	$ (185)	$ (217)	$ (261)
Combined Points for Other Factors (OF)	10.5	11.4	9.4	10.1	9.9	10.6	10.2	9.6
Value of OF based on Median ($ million)	$ 32	$ 35	$ 29	$ 31	$ 31	$ 33	$ 31	$ 30
Average NB incl. OF ($/kW)	$ 304	$ 380	$ 304	$ 381	$ 232	$ 420	$ 339	$ 204
Average NB incl. OF ($/million)	$ 173	$ 249	$ 171	$ 238	$ 181	$ 299	$ 293	$ 157
Option Value (OV) ($/kW)	$ 270	$ 234	$ 272	$ 246	$ 197	$ 215	$ 177	$ 199
Option Value (OV) ($ million)	$ 154	$ 154	$ 154	$ 153	$ 153	$ 153	$ 153	$ 153
Average NB incl. OF and OV ($/kW)	**$ 575**	**$ 614**	**$ 575**	**$ 627**	**$ 428**	**$ 636**	**$ 515**	**$ 403**
Average NB incl. OF and OV ($/million)	**$ 327**	**$ 403**	**$ 325**	**$ 391**	**$ 334**	**$ 452**	**$ 446**	**$ 309**
Rank ($/kW)	21	19	20	18	27	17	25	28
Rank ($ million)	24	21	25	22	23	15	17	26

Note that rankings at the bottom of the graphic are among all portfolios.
Note that $/kW figures are calculated using average contract quantity over the contract term

Portfolio Name	**Portfolio 71**	**Portfolio 72**	**Portfolio 73**	**Portfolio 74**	**Portfolio 75**	**Portfolio 76**	**Portfolio 77**	**Portfolio 78**
Projects	Portfolio E, D, I	Portfolio E, D, I, C	Portfolio E, D, O	Portfolio E, D, I, O	Portfolio E, D, I, O, Q	Portfolio E, D, I, C, O	Portfolio E, D, I, C, O, Q	Portfolio E, D, O, Q, M
Portfolio Mix	1 CCGT, 1 EE, 1 DR	1 CCGT, 1 EE, 2 DR	1 CCGT, 1 EE, 1 Peaker	1 CCGT, 1 EE, 1 DR, 1 Peaker	1 CCGT, 1 EE, 1 DR, 2 Peaker	1 CCGT, 1 EE, 2 DR, 1 Peaker	1 CCGT, 1 EE, 2 DR, 2 Peaker	1 CCGT, 1 EE, 3 Peaker
Portfolio Size (Total MW)	700	850	691	766	953	916	1103	965
Average Benefits - ENERGY ($/kW)	$ 626	$ 555	$ 662	$ 597	$ 485	$ 530	$ 447	$ 493
Average Benefits - ENERGY ($ million)	$ 359	$ 366	$ 376	$ 375	$ 379	$ 379	$ 389	$ 381
Average Benefits - CAPACITY ($/kW)	$ 755	$ 714	$ 738	$ 711	$ 575	$ 685	$ 545	$ 568
Average Benefits - CAPACITY ($ million)	$ 433	$ 471	$ 420	$ 447	$ 450	$ 490	$ 474	$ 438
Average Benefits - LFRM ($/kW)	$ (1)	$ (1)	$ (12)	$ (12)	$ (22)	$ (9)	$ (20)	$ (22)
Average Benefits - LFRM ($ million)	$ (1)	$ (1)	$ (7)	$ (7)	$ (17)	$ (7)	$ (17)	$ (17)
Average Benefits ($/kW)	$ 1,380	$ 1,267	$ 1,387	$ 1,297	$ 1,038	$ 1,206	$ 973	$ 1,039
Average Benefits ($million)	$ 791	$ 836	$ 789	$ 814	$ 812	$ 862	$ 846	$ 802
Average Costs ($/kW)	$ 558	$ 519	$ 543	$ 522	$ 513	$ 491	$ 487	$ 520
Average Costs ($ million)	$ 320	$ 342	$ 309	$ 328	$ 401	$ 351	$ 423	$ 401
Average Net Benefits (NB) ($/kW)	**$ 821**	**$ 748**	**$ 845**	**$ 774**	**$ 525**	**$ 715**	**$ 486**	**$ 519**
Average Net Benefits (NB) ($ million)	**$ 471**	**$ 494**	**$ 481**	**$ 486**	**$ 411**	**$ 511**	**$ 423**	**$ 401**
MAX of NB across scenarios ($MM)	$ 1,468	$ 1,502	$ 1,526	$ 1,506	$ 1,473	$ 1,467	$ 1,483	$ 1,475
MIN of NB across scenarios ($MM)	$ (104)	$ (73)	$ (107)	$ (66)	$ (144)	$ (77)	$ (168)	$ (146)
Combined Points for Other Factors (OF)	11.4	11.3	10.4	10.4	8.5	10.2	8.4	8.4
Value of OF based on Median ($ million)	$ 35	$ 35	$ 32	$ 32	$ 26	$ 32	$ 26	$ 26
Average NB incl. OF ($/kW)	$ 883	$ 801	$ 901	$ 825	$ 558	$ 759	$ 516	$ 553
Average NB incl. OF ($/million)	$ 506	$ 529	$ 513	$ 518	$ 437	$ 543	$ 449	$ 427
Option Value (OV) ($/kW)	$ -	$ -	$ -	$ -	$ 3	$ -	$ 3	$ 3
Option Value (OV) ($ million)	$ -	$ -	$ -	$ -	$ 2	$ -	$ 2	$ 2
Average NB incl. OF and OV ($/kW)	**$ 883**	**$ 801**	**$ 901**	**$ 825**	**$ 561**	**$ 759**	**$ 519**	**$ 556**
Average NB incl. OF and OV ($/million)	**$ 506**	**$ 529**	**$ 513**	**$ 518**	**$ 439**	**$ 543**	**$ 451**	**$ 429**
Rank ($/kW)	3	9	2	8	22	12	24	23
Rank ($ million)	13	8	12	10	18	5	16	19

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Note that rankings at the bottom of the graphic are among all portfolios.
Note that $/kW figures are calculated using average contract quantity over the contract term

Portfolio Name	Portfolio 79	Portfolio 85	Portfolio 87	Portfolio 88	Portfolio 89	Portfolio 110	Portfolio 111
Projects	Portfolio E, D, O, Q	Portfolio E, D, I, O, R	Portfolio E, D, I, C, O, R	Portfolio E, D, O, K, R	Portfolio E, D, O, R	Portfolio D, O	Portfolio D, I, O
Portfolio Mix	1 CCGT, 1 EE, 2 Peaker	1 CCGT, 1 EE, 1 DR, 2 Peaker	1 CCGT, 1 EE, 2 DR, 2 Peaker	1 CCGT, 1 EE, 3 Peaker	1 CCGT, 1 EE, 2 Peaker	1 EE, 1 Peaker	1 EE, 1 DR, 1 Peaker
Portfolio Size (Total MW)	878	861.7	1011.7	1065.7	786.7	71	146
Average Benefits - ENERGY ($/kW)	$ 572	$ 609	$ 537	$ 473	$ 632	$ -	$ -
Average Benefits - ENERGY ($ million)	$ 414	$ 415	$ 412	$ 426	$ 417	$ -	$ -
Average Benefits - CAPACITY ($/kW)	$ 618	$ 688	$ 650	$ 501	$ 691	$ 1,405	$ 1,004
Average Benefits - CAPACITY ($ million)	$ 447	$ 469	$ 499	$ 451	$ 455	$ 88	$ 119
Average Benefits - LFRM ($/kW)	$ (23)	$ (9)	$ (9)	$ (24)	$ (10)	$ (59)	$ (36)
Average Benefits - LFRM ($ million)	$ (17)	$ (6)	$ (7)	$ (22)	$ (6)	$ (4)	$ (4)
Average Benefits ($/kW)	$ 1,167	$ 1,288	$ 1,178	$ 950	$ 1,313	$ 1,346	$ 968
Average Benefits ($million)	$ 845	$ 878	$ 904	$ 856	$ 865	$ 84	$ 115
Average Costs ($/kW)	$ 530	$ 530	$ 499	$ 529	$ 520	$ 186	$ 270
Average Costs ($ million)	$ 383	$ 361	$ 383	$ 477	$ 343	$ 12	$ 32
Average Net Benefits (NB) ($/kW)	**$ 637**	**$ 758**	**$ 679**	**$ 421**	**$ 793**	**$ 1,160**	**$ 698**
Average Net Benefits (NB) ($ million)	**$ 461**	**$ 517**	**$ 522**	**$ 379**	**$ 522**	**$ 73**	**$ 83**
MAX of NB across scenarios ($MM)	$ 1,668	$ 1,754	$ 1,707	$ 1,634	$ 1,770	$ 305	$ 431
MIN of NB across scenarios ($MM)	$ (133)	$ (116)	$ (149)	$ (243)	$ (79)	$ (23)	$ (10)
Combined Points for Other Factors (OF)	9.3	9.2	8.7	7.2	9.5	5.1	5.8
Value of OF based on Median ($ million)	$ 29	$ 28	$ 27	$ 22	$ 29	$ 16	$ 18
Average NB incl. OF ($/kW)	$ 677	$ 800	$ 714	$ 445	$ 837	$ 1,409	$ 848
Average NB incl. OF ($/million)	$ 490	$ 545	$ 548	$ 401	$ 552	$ 88	$ 100
Option Value (OV) ($/kW)	$ 3	$ -	$ -	$ 17	$ -	$ -	$ -
Option Value (OV) ($ million)	$ 2	$ -	$ -	$ 15	$ -	$ -	$ -
Average NB incl. OF and OV ($/kW)	**$ 680**	**$ 800**	**$ 714**	**$ 462**	**$ 837**	**$ 1,409**	**$ 848**
Average NB incl. OF and OV ($/million)	**$ 492**	**$ 545**	**$ 548**	**$ 416**	**$ 552**	**$ 88**	**$ 100**
Rank ($/kW)	16	10	15	26	5	1	4
Rank ($ million)	14	4	2	20	1	28	27

Note that rankings at the bottom of the graphic are among all portfolios.
Note that $/kW figures are calculated using average contract quantity over the contract term

Portfolio Name	**Portfolio 112**	**Portfolio 113**	**Portfolio 114**	**Portfolio 174**	**Portfolio 176**	**Portfolio 189**
Projects	Portfolio E, D, B, I, O	Portfolio B, E, D, I, O, R	Portfolio K, O, Q, R	Portfolio E, I, O	Portfolio E, I, C, O	Portfolio E, O, R
Portfolio Mix	1 CCGT, 1 EE, 2 DR, 1 Peaker	1 CCGT, 1 EE, 2 DR, 2 Peaker	4 Peaker	1 CCGT, 1 DR, 1 Peaker	1 CCGT, 2 DR, 1 Peaker	1 CCGT, 2 Peaker
Portfolio Size (Total MW)	841	936.7	627.7	761	911	781.7
Average Benefits - ENERGY ($/kW)	$ 549	$ 558	$ 74	$ 601	$ 533	$ 637
Average Benefits - ENERGY ($ million)	$ 379	$ 415	$ 44	$ 375	$ 379	$ 417
Average Benefits - CAPACITY ($/kW)	$ 678	$ 652	$ 421	$ 711	$ 685	$ 687
Average Benefits - CAPACITY ($ million)	$ 468	$ 485	$ 249	$ 444	$ 487	$ 450
Average Benefits - LFRM ($/kW)	$ (10)	$ (8)	$ (51)	$ (12)	$ (10)	$ (10)
Average Benefits - LFRM ($ million)	$ (7)	$ (6)	$ (30)	$ (7)	$ (7)	$ (6)
Average Benefits ($/kW)	$ 1,216	$ 1,202	$ 444	$ 1,301	$ 1,209	$ 1,314
Average Benefits ($million)	$ 840	$ 894	$ 262	$ 811	$ 859	$ 860
Average Costs ($/kW)	$ 508	$ 516	$ 411	$ 522	$ 490	$ 520
Average Costs ($ million)	$ 351	$ 384	$ 242	$ 326	$ 348	$ 340
Average Net Benefits (NB) ($/kW)	**$ 708**	**$ 686**	**$ 34**	**$ 779**	**$ 719**	**$ 794**
Average Net Benefits (NB) ($ million)	**$ 489**	**$ 510**	**$ 20**	**$ 486**	**$ 511**	**$ 520**
MAX of NB across scenarios ($MM)	$ 1,457	$ 1,739	$ 926	$ 1,506	$ 1,467	$ 1,771
MIN of NB across scenarios ($MM)	$ (76)	$ (144)	$ (285)	$ (66)	$ (76)	$ (87)
Combined Points for Other Factors (OF)	9.9	9.1	4.9	10.1	10.1	9.1
Value of OF based on Median ($ million)	$ 31	$ 28	$ 15	$ 31	$ 31	$ 28
Average NB incl. OF ($/kW)	$ 752	$ 723	$ 59	$ 829	$ 763	$ 837
Average NB incl. OF ($/million)	$ 520	$ 538	$ 35	$ 517	$ 542	$ 548
Option Value (OV) ($/kW)	$ -	$ -	$ 77	$ -	$ -	$ -
Option Value (OV) ($ million)	$ -	$ -	$ 46	$ -	$ -	$ -
Average NB incl. OF and OV ($/kW)	**$ 752**	**$ 723**	**$ 137**	**$ 829**	**$ 763**	**$ 837**
Average NB incl. OF and OV ($/million)	**$ 520**	**$ 538**	**$ 81**	**$ 517**	**$ 542**	**$ 548**
Rank ($/kW)	13	14	29	7	11	6
Rank ($ million)	9	7	29	11	6	3

6.3 Portfolios incorporating the quantity impact for energy efficiency

Note that $/kW figures are calculated using average contract quantity over the contract term

Portfolio Name	Project Dq	Project 74q	Project 76q	Project 85q	Project 89q
Projects	358	Portfolio E, D, I, O	Portfolio E, D, I, C, O	Portfolio E, D, I, O, R	Portfolio E, D, O, R
Portfolio Mix	EE	1 CCGT, 1 EE, 1 DR, 1 Peaker	1 CCGT, 1 EE, 2 DR, 1 Peaker	1 CCGT, 1 EE, 1 DR, 2 Peaker	1 CCGT, 1 EE, 2 Peaker
Portfolio Size (Total MW)	5	766	916	862	787
Average Benefits - ENERGY ($/kW)	$ 2,824	$ 617	$ 547	$ 627	$ 651
Average Benefits - ENERGY ($ million)	$ 12	$ 387	$ 391	$ 427	$ 429
Average Benefits - CAPACITY ($/kW)	$ 422	$ 711	$ 685	$ 688	$ 691
Average Benefits - CAPACITY ($ million)	$ 2	$ 447	$ 490	$ 469	$ 455
Average Benefits - LFRM ($/kW)	$ -	$ (12)	$ (9)	$ (9)	$ (10)
Average Benefits - LFRM ($ million)	$ -	$ (7)	$ (7)	$ (6)	$ (6)
Average Benefits ($/kW)	$ 3,246	$ 1,316	$ 1,223	$ 1,306	$ 1,332
Average Benefits ($million)	$ 14	$ 826	$ 874	$ 890	$ 877
Average Costs ($/kW)	$ 566	$ 522	$ 491	$ 530	$ 520
Average Costs ($ million)	$ 2	$ 328	$ 351	$ 361	$ 343
Average Net Benefits (NB) ($/kW)	**$ 2,680**	**$ 794**	**$ 732**	**$ 776**	**$ 812**
Average Net Benefits (NB) ($ million)	**$ 12**	**$ 499**	**$ 524**	**$ 529**	**$ 535**
MAX of NB across scenarios ($MM)	$ 21	$ 1,528	$ 1,489	$ 1,777	$ 1,792
MIN of NB across scenarios ($MM)	$ 6	$ (60)	$ (67)	$ (106)	$ (69)
Combined Points for Other Factors (OF)	7.8	10.4	10.2	9.2	9.5
Value of OF based on Median ($ million)	$ 24	$ 32	$ 32	$ 28	$ 29
Average NB incl. OF ($/kW)	$ 8,102	$ 845	$ 776	$ 818	$ 856
Average NB incl. OF ($/million)	$ 36	$ 531	$ 555	$ 557	$ 564
Option Value (OV) ($/kW)	$ -	$ -	$ -	$ -	$ -
Option Value (OV) ($ million)	$ -	$ -	$ -	$ -	$ -
Average NB incl. OF and OV ($/kW)	**$ 8,102**	**$ 845**	**$ 776**	**$ 818**	**$ 856**
Average NB incl. OF and OV ($/million)	**$ 36**	**$ 531**	**$ 555**	**$ 557**	**$ 564**

6.4 Individual project results

Note that rankings at the bottom of the graphic are among all individual projects.
Note that $/kW figures are calculated using average contract quantity over the contract term

Portfolio Name	**Project A**	**Project B**	**Project C**	**Project D**	**Project E**	**Project G**	**Project I**
Projects	146	234	272	358	409	592	646-A
Portfolio Mix	CCGT	DR	DR	EE	CCGT	DR	DR
Portfolio Size (Total MW)	630	75	150	5	620	150	75
Average Benefits - ENERGY ($/kW)	$ 396	$ -	$ -	$ -	$ 586	$ -	$ -
Average Benefits - ENERGY ($ million)	$ 240	$ -	$ -	$ -	$ 359	$ -	$ -
Average Benefits - CAPACITY ($/kW)	$ 273	$ 1,231	$ 892	$ 422	$ 682	$ 1,017	$ 1,299
Average Benefits - CAPACITY ($ million)	$ 166	$ 92	$ 127	$ 2	$ 417	$ 127	$ 92
Average Benefits - LFRM ($/kW)	$ (0)	$ -	$ -	$ -	$ (1)	$ -	$ (12)
Average Benefits - LFRM ($ million)	$ (0)	$ -	$ -	$ -	$ (0)	$ -	$ (1)
Average Benefits ($/kW)	$ 669	$ 1,231	$ 892	$ 422	$ 1,267	$ 1,017	$ 1,287
Average Benefits ($million)	$ 406	$ 92	$ 127	$ 2	$ 775	$ 127	$ 91
Average Costs ($/kW)	$ 441	$ 318	$ 182	$ 566	$ 490	$ 170	$ 281
Average Costs ($ million)	$ 268	$ 24	$ 26	$ 2	$ 300	$ 21	$ 20
Average Net Benefits (NB) ($/kW)	**$ 228**	**$ 913**	**$ 710**	**$ (144)**	**$ 778**	**$ 847**	**$ 1,006**
Average Net Benefits (NB) ($ million)	**$ 138**	**$ 68**	**$ 101**	**$ (1)**	**$ 476**	**$ 106**	**$ 71**
MAX of NB across scenarios ($MM)	$ 927	$ 306	$ 435	$ 2	$ 1,475	$ 444	$ 308
MIN of NB across scenarios ($MM)	$ (176)	$ 4	$ 11	$ (2)	$ (106)	$ 20	$ 8
Combined Points for Other Factors (OF)	8.2	6.7	8.6	6.0	10.2	7.5	8.1
Value of OF based on Median ($ million)	$ 25	$ 21	$ 26	$ 18	$ 31	$ 23	$ 25
Average NB incl. OF ($/kW)	$ 269	$ 1,188	$ 896	$ 4,039	$ 829	$ 1,033	$ 1,357
Average NB incl. OF ($/million)	$ 163	$ 89	$ 127	$ 18	$ 507	$ 129	$ 96
Option Value (OV) ($/kW)	$ 254	$ -	$ -	$ -	$ -	$ -	$ -
Option Value (OV) ($ million)	$ 154	$ -	$ -	$ -	$ -	$ -	$ -
Average NB incl. OF and OV ($/kW)	**$ 523**	**$ 1,188**	**$ 896**	**$ 4,039**	**$ 829**	**$ 1,033**	**$ 1,357**
Average NB incl. OF and OV ($/million)	**$ 318**	**$ 89**	**$ 127**	**$ 18**	**$ 507**	**$ 129**	**$ 96**
Rank NB incl. OF and OV ($/kW)	**9**	**3**	**6**	**1**	**7**	**4**	**2**
Rank NB incl. OF and OV ($ million)	**2**	**7**	**4**	**13**	**1**	**3**	**5**

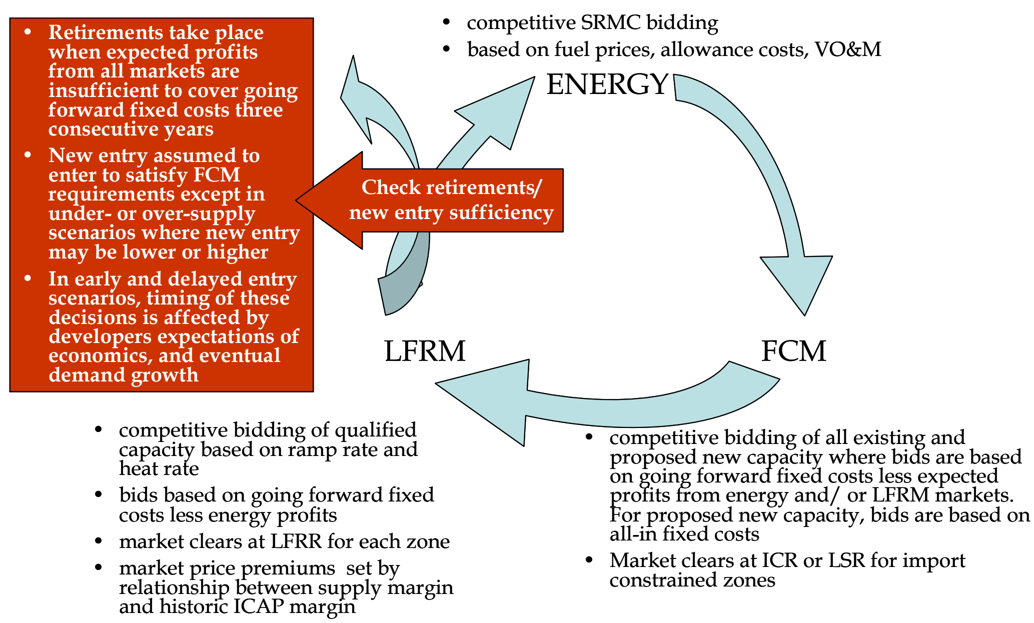
Note that rankings at the bottom of the graphic are among all individual projects.
Note that $/kW figures are calculated using average contract quantity over the contract term

Portfolio Name	**Project J**	**Project K**	**Project M**	**Project N**	**Project O**	**Project P**	**Project Q**	**Project R**
Projects	654-B	654-C	776-A	776-B	851	892	951	993
Portfolio Mix	Peaker	Peaker	Peaker	Peaker	Peaker	Peaker	Peaker	Peaker
Portfolio Size (Total MW)	188	280	87	87	66	93.5	188	95.7
Average Benefits - ENERGY ($/kW)	$ 52	$ 34	$ -	$ -	$ -	$ -	$ 33	$ -
Average Benefits - ENERGY ($ million)	$ 10	$ 9	$ -	$ -	$ -	$ -	$ 6	$ -
Average Benefits - CAPACITY ($/kW)	$ 689	$ 644	$ 322	$ 322	$ 923	$ 1,111	$ 685	$ 979
Average Benefits - CAPACITY ($ million)	$ 127	$ 177	$ 28	$ 28	$ 61	$ 103	$ 127	$ 94
Average Benefits - LFRM ($/kW)	$ (70)	$ (67)	$ 5	$ 5	$ (56)	$ 7	$ (73)	$ (1)
Average Benefits - LFRM ($ million)	$ (13)	$ (19)	$ 0	$ 0	$ (4)	$ 1	$ (14)	$ (0)
Average Benefits ($/kW)	$ 671	$ 610	$ 328	$ 328	$ 867	$ 1,118	$ 645	$ 978
Average Benefits ($million)	$ 124	$ 168	$ 29	$ 29	$ 57	$ 104	$ 120	$ 94
Average Costs ($/kW)	$ 632	$ 477	$ 284	$ 320	$ 147	$ 824	$ 452	$ 463
Average Costs ($ million)	$ 117	$ 131	$ 25	$ 28	$ 10	$ 76	$ 84	$ 44
Average Net Benefits (NB) ($/kW)	**$ 39**	**$ 133**	**$ 43**	**$ 8**	**$ 720**	**$ 294**	**$ 193**	**$ 515**
Average Net Benefits (NB) ($ million)	**$ 7**	**$ 36**	**$ 4**	**$ 1**	**$ 48**	**$ 27**	**$ 36**	**$ 49**
MAX of NB across scenarios ($MM)	$ 367	$ 450	$ 34	$ 31	$ 226	$ 246	$ 377	$ 270
MIN of NB across scenarios ($MM)	$ (100)	$ (131)	$ (22)	$ (26)	$ (22)	$ (46)	$ (66)	$ (41)
Combined Points for Other Factors (OF)	4.5	4.6	3.7	3.7	4.7	1.4	4.2	3.3
Value of OF based on Median ($ million)	$ 14	$ 14	$ 11	$ 11	$ 14	$ 4	$ 13	$ 10
Average NB incl. OF ($/kW)	$ 114	$ 185	$ 175	$ 140	$ 937	$ 340	$ 262	$ 623
Average NB incl. OF ($/million)	$ 21	$ 51	$ 15	$ 12	$ 62	$ 32	$ 49	$ 60
Option Value (OV) ($/kW)	$ 147	$ 147	$ -	$ -	$ -	$ -	$ 29	$ -
Option Value (OV) ($ million)	$ 27	$ 40	$ -	$ -	$ -	$ -	$ 5	$ -
Average NB incl. OF and OV ($/kW)	**$ 261**	**$ 332**	**$ 175**	**$ 140**	**$ 937**	**$ 340**	**$ 291**	**$ 623**
Average NB incl. OF and OV ($/million)	**$ 48**	**$ 91**	**$ 15**	**$ 12**	**$ 62**	**$ 32**	**$ 54**	**$ 60**
Rank NB incl. OF and OV ($/kW)	**13**	**11**	**14**	**15**	**5**	**10**	**12**	**8**
Rank NB incl. OF and OV ($ million)	**11**	**6**	**14**	**15**	**8**	**12**	**10**	**9**

7 Appendix B: Description of LEI models used for bid evaluation

Future market prices in the ISO-NE Markets were projected using London Economics' proprietary production cost-based network simulation model, PoolMod, along with a suite of Excel-based models created specifically to project market clearing prices (and costs to Connecticut load) in the FCM and the LFRM. The three ISO-NE Markets - Energy, FCM, and LFRM – are interlinked and the models respect those linkages. For example, generators are expected to offer their capacity (under rational bidding behavior) into the FCM at a price equal to their going forward fixed costs less expected profits from the Energy Market and the LFRM. The supply stack into LFRM is also created based on going forward fixed costs (and the auction clearing price (and namely the LFRM premium[36]) is a function of that supply). The diagram below, Figure 21, highlights the process and sequencing used in the modeling and the inter-relationships between the three models, and the entry and retirement decisions of resources. In the subsections below, we describe each of the models and key assumptions.

Figure 21. Interaction between energy, LFRM and FCM modeling



7.1 Energy model

The DPUC utilized London Economic's proprietary network simulation model as the foundation for the energy price forecast. PoolMod simulated the dispatch of New England's generating resources (and imports) on a least cost basis in order to meet projected hourly load

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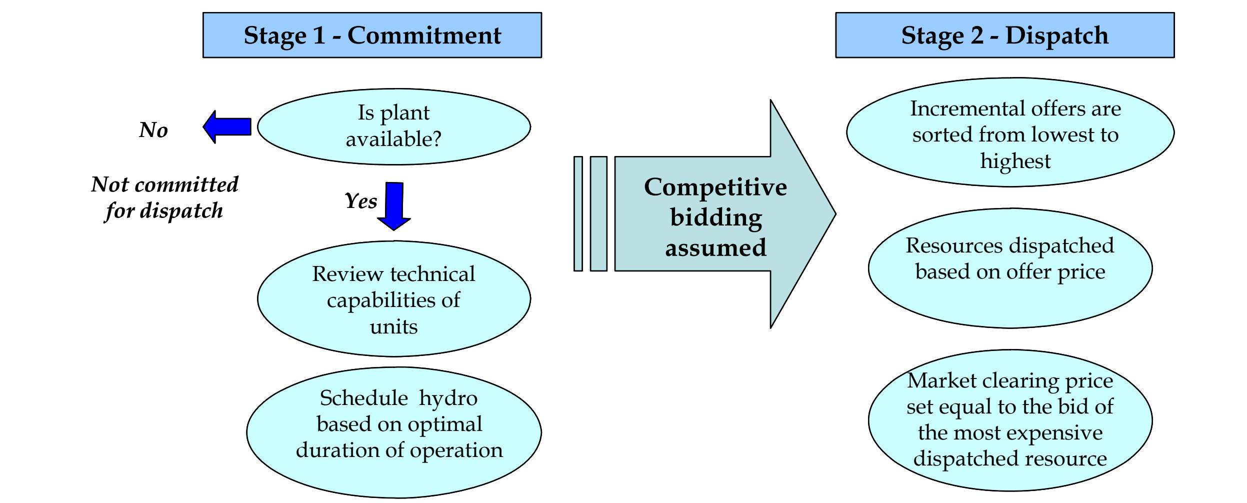
36 The prices received in the LFRM are also expected to be netted against the capacity clearing prices received in the FCM.

(and export demand), subject to technical constraints on operations for generation and availability of transmission capacity.

PoolMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing[37], commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. First, PoolMod determines a 'near' optimal maintenance schedule on an annual basis having regard for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, PoolMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 22. PoolMod's two-stage process



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

PoolMod is a transportation-based model, so it takes into account thermal limits on the transmission network. For the Economic Analysis, the entire ISO New England's control area was modeled on a zonal basis, consistent with the assumptions used in RSP 2006.[38]

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

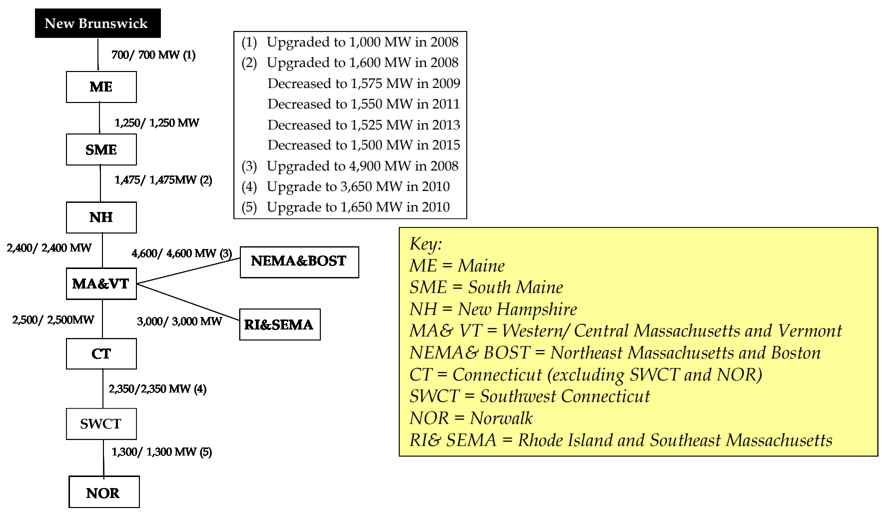
38 Imports and export demand from adjoining markets were also considered in PoolMod simulations in order to realistically capture the actual operating dynamics in the ISO-NE Energy Market, and to maintain linkages to the FCM model, which incorporates the fact that resources from external markets may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

To simulate the New England energy market, the following assumptions were incorporated into our modeling.

Transmission topology

For long-term planning purposes, ISO-NE groups the control area into of thirteen sub-regions (RSP zones). We simplified the thirteen sub-region network model per the RSP into nine sub-regional market areas based on historical LMPs. In order to facilitate the modeling, we also linearized the topology, as seen in Figure 23 below.

Figure 23. Linear topology of energy modeling for New England



Existing Supply

The existing capacity in our modeling was calibrated based on the most recent ISO-NE Regional System Plan (RSP), Capacity, Energy, Load & Transmission (CELT), and Seasonal Claimed Capability Reports (SCC). We also updated the supply resources with the most recent developments in the New England market. The existing supply resources by fuel type are shown in the table below.

Figure 24. 2007 summer rating capacity by modeling sub-zone and fuel type (MW)

	Maine	SME	NH	MA & VT	NEMA & BOST	CT	SWCT	NOR	RI & SEMA
Nuclear	0	0	1,244	620	0	2,037	0	0	685
Coal	0	0	528	144	312	181	372	0	1,187
Gas	735	514	651	555	1,360	0	662	0	3,222
Oil and dual-fuel	297	845	992	1,185	1,570	2,014	782	396	3,281
Other	275	77	166	108	99	123	65	0	102
Hydro	462	64	483	2,153	34	34	116	0	3
Demand Response	56	0	22	61	111	424	338	0	40
Total	**1,825**	**1,501**	**4,086**	**4,826**	**3,486**	**4,813**	**2,335**	**396**	**8,521**

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

Fuel price assumption

The Base Case gas price forecast was developed using NYMEX forwards for the first six years of the forecast timeframe (2007-2012) and then blended into the long-term forecast from the *EIA Annual Energy Outlook 2007*. High and Low gas prices were derived based on observed historical forecast errors for gas from EIA. Figure 25 below presents the gas price forecasts for the base, high, and low cases.

Figure 25. Projected Boston Citygate natural gas prices under Base Case, High Case and Low Case (nominal $/MMBtu)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Base Case	$9.17	$9.62	$9.29	$8.93	$8.53	$8.15	$8.05	$8.22	$8.25	$8.54	$8.99	$9.00	$9.06	$9.35	$9.51
High Case	$9.17	$9.96	$10.76	$11.57	$12.40	$13.23	$13.96	$14.70	$15.60	$17.00	$18.81	$19.75	$20.80	$22.42	$23.78
Low Case	$9.17	$8.43	$7.67	$6.89	$6.11	$5.31	$4.45	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60

The oil price forecast was based on 18 month forwards for heating oil and six year forwards for light sweet crude oil, both available from NYMEX. The starting point (2007) for the distillate oil forecast is based on the heating oil forwards from NYMEX. The NYMEX futures for light sweet crude oil were then used to escalate the distillate price forecast over the short term. A distillate-residual differential was applied to the distillate oil forecast, based on the reported differentials from *EIA Annual Energy Outlook 2007*, in order to create the residual oil price forecast. In the longer term, both the residual and distillate oil price tracks were escalated based on the implied projected rate of growth for crude oil from *EIA Annual Energy Outlook 2007*.

The coal price assumptions were based on the average delivered price of coal (for the period January 2004 through July 2006) to each plant, escalated to nominal terms using the annual rate of change implied in the coal price index and inflation rate from *EIA Annual Energy Outlook 2007*. Figure 26 presents the oil and coal price projections.

Figure 26. Projected oil and coal prices under Base Case, High Case and Low Case (nominal $/MMBtu)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Distillate Oil															
Base Case	$13.54	$14.15	$14.09	$13.93	$13.77	$13.63	$13.40	$13.53	$13.82	$14.03	$14.59	$14.99	$15.47	$15.78	$16.30
High Case	$13.54	$14.65	$16.32	$18.05	$20.01	$22.12	$23.24	$24.19	$26.12	$27.94	$30.53	$32.90	$35.52	$37.85	$40.74
Low Case	$13.54	$12.39	$11.63	$10.75	$9.86	$8.87	$7.41	$5.93	$6.03	$5.91	$5.84	$6.00	$6.15	$6.08	$6.17
Residual Oil															
Base Case	$6.83	$7.50	$7.76	$7.83	$7.93	$8.02	$7.87	$8.02	$8.36	$8.51	$8.86	$9.14	$9.53	$9.75	$10.19
High Case	$6.83	$7.76	$8.98	$10.15	$11.52	$13.02	$13.65	$14.34	$15.79	$16.95	$18.55	$20.06	$21.88	$23.39	$25.48
Low Case	$6.83	$6.57	$6.40	$6.05	$5.68	$5.22	$4.35	$3.51	$3.64	$3.59	$3.55	$3.66	$3.79	$3.75	$3.86
Coal - New England average															
Base/ High/ Low	$2.41	$2.45	$2.31	$2.37	$2.36	$2.60	$2.63	$2.65	$2.67	$2.71	$2.74	$2.76	$2.80	$2.85	$2.91

Demand forecast

The demand assumptions used in the modeling rely on ISO-NE's projections for demand under the reference case (50/50) and high and low economic cases. These forecasts were published by ISO-NE as part of Regional System Plan (RSP) 2006. ISO-NE's forecast extends for ten years, while the modeling looked over a longer time period in order to accommodate contract terms of up to fifteen years. For each year after 2015, we used the underlying year-on-year declining growth trend in the ISO-NE's projected peak demand growth rate.

Figure 27. Projected demand for New England and Connecticut under ISO-NE's reference case (50/50), high economic case, and low economic case, 2007 – 2021

Reference case

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ISO-NE															
Peak demand (MW)	27,355	27,900	28,540	29,185	29,885	30,515	31,020	31,480	31,895	32,274	32,609	32,922	33,207	33,477	33,725
Energy (GWh)	133,975	135,775	138,020	140,330	142,790	145,160	147,225	149,185	151,085	152,933	154,721	156,465	158,178	159,863	161,531
Growth in peak demand		*2.0%*	*2.3%*	*2.3%*	*2.4%*	*2.1%*	*1.7%*	*1.5%*	*1.3%*	*1.2%*	*1.0%*	*1.0%*	*0.9%*	*0.8%*	*0.7%*
CT (rest of CT)															
Peak demand (MW)	3,630	3,695	3,780	3,865	3,955	4,050	4,115	4,175	4,230	4,280	4,327	4,369	4,408	4,443	4,475
Energy (GWh)	17,105	17,320	17,600	17,915	18,235	18,565	18,825	19,080	19,310	19,526	19,725	19,909	20,080	20,237	20,382
Growth in peak demand		*1.8%*	*2.3%*	*2.2%*	*2.3%*	*2.4%*	*1.6%*	*1.5%*	*1.3%*	*1.2%*	*1.1%*	*1.0%*	*0.9%*	*0.8%*	*0.7%*
SWCT															
Peak demand (MW)	3,650	3,720	3,805	3,895	3,990	4,070	4,125	4,175	4,225	4,273	4,320	4,365	4,409	4,452	4,493
Energy (GWh)	17,190	17,415	17,715	18,040	18,370	18,650	18,860	19,065	19,250	19,424	19,583	19,731	19,868	19,994	20,111
Growth in peak demand		*1.9%*	*2.3%*	*2.4%*	*2.4%*	*2.0%*	*1.4%*	*1.2%*	*1.2%*	*1.1%*	*1.1%*	*1.0%*	*1.0%*	*1.0%*	*0.9%*

High economic case

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ISO-NE															
Peak demand (MW)	27,579	28,513	29,418	30,327	31,294	32,185	32,954	33,678	34,355	34,993	35,588	36,145	36,666	37,152	37,605
Energy (GWh)	136,655	140,393	143,967	147,581	151,339	154,988	158,342	161,586	164,752	167,829	170,824	173,737	176,571	179,328	182,010
Growth in peak demand		*3.4%*	*3.2%*	*3.1%*	*3.2%*	*2.8%*	*2.4%*	*2.2%*	*2.0%*	*1.9%*	*1.7%*	*1.6%*	*1.4%*	*1.3%*	*1.2%*
CT (rest of CT)															
Peak demand (MW)	3,646	3,756	3,865	3,978	4,096	4,215	4,307	4,395	4,477	4,554	4,626	4,694	4,757	4,816	4,871
Energy (GWh)	17,387	17,801	18,221	18,662	19,104	19,564	19,950	20,326	20,695	21,055	21,408	21,752	22,088	22,415	22,735
Growth in peak demand		*3.0%*	*2.9%*	*2.9%*	*3.0%*	*2.9%*	*2.2%*	*2.0%*	*1.9%*	*1.7%*	*1.6%*	*1.5%*	*1.3%*	*1.2%*	*1.1%*
SWCT															
Peak demand (MW)	3,666	3,778	3,891	4,008	4,130	4,240	4,320	4,395	4,466	4,533	4,596	4,655	4,710	4,762	4,811
Energy (GWh)	17,476	17,902	18,335	18,790	19,246	19,657	19,992	20,314	20,629	20,934	21,231	21,519	21,798	22,069	22,331
Growth in peak demand		*3.1%*	*3.0%*	*3.0%*	*3.0%*	*2.7%*	*1.9%*	*1.7%*	*1.6%*	*1.5%*	*1.4%*	*1.3%*	*1.2%*	*1.1%*	*1.0%*

Low economic case

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ISO-NE															
Peak demand (MW)	27,133	27,279	27,641	28,029	28,466	28,833	29,071	29,269	29,415	29,532	29,627	29,705	29,769	29,822	29,866
Energy (GWh)	131,295	131,143	132,054	133,132	134,330	135,451	136,252	136,968	137,582	138,133	138,621	139,057	139,447	139,798	140,114
Growth in peak demand		*0.5%*	*1.3%*	*1.4%*	*1.6%*	*1.3%*	*0.8%*	*0.7%*	*0.5%*	*0.4%*	*0.3%*	*0.3%*	*0.2%*	*0.2%*	*0.1%*
CT (rest of CT)															
Peak demand (MW)	3,610	3,635	3,688	3,749	3,813	3,878	3,915	3,949	3,974	3,995	4,011	4,024	4,034	4,042	4,048
Energy (GWh)	16,822	16,825	16,978	17,170	17,356	17,557	17,683	17,809	17,911	18,003	18,082	18,151	18,211	18,264	18,309
Growth in peak demand		*0.7%*	*1.5%*	*1.7%*	*1.7%*	*1.7%*	*1.0%*	*0.9%*	*0.6%*	*0.5%*	*0.4%*	*0.3%*	*0.3%*	*0.2%*	*0.2%*
SWCT															
Peak demand (MW)	3,629	3,657	3,714	3,778	3,845	3,899	3,926	3,950	3,964	3,974	3,981	3,986	3,990	3,992	3,994
Energy (GWh)	16,908	16,921	17,084	17,288	17,486	17,641	17,719	17,799	17,854	17,901	17,938	17,969	17,993	18,014	18,030
Growth in peak demand		*0.8%*	*1.6%*	*1.7%*	*1.8%*	*1.4%*	*0.7%*	*0.6%*	*0.4%*	*0.3%*	*0.2%*	*0.1%*	*0.1%*	*0.1%*	*0.0%*

Operation parameters

For operating parameters, if available, we applied the plant specific data. Otherwise, we used a standard set of assumptions as shown in Figure 28 below.

Figure 28. Indicative operating parameters for generation facilities

	MSG (%)	VOM ($/MWh)	Min On/ OFF (hour)	EFORd (%)	Maintenance (week)
Existing					
Nuclear	85%	$3.36	24	2%	4
Coal ST	32%	$1.57	24	7%	5
Gas CC	35%	$0.94	8	6%	5
Gas GT	47%	$0.95	1	7%	5
Gas ST	50%	$1.28	4	7%	5
Petro CC	29%	$2.38	1	6.79% for residual	5 for residual
Petro GT	53%	$1.90	1	8.40% for distillate	1 for distillate
Petro ST	29%	$1.35	1		
New Entry					
CCGT	35%	$ 1.80	8	6%	5
peaker	50%	$ 2.80	4	7%	5

Note: The numbers above are the average within the same class/ fuel type. More class/ plant specific parameters were applied in the actual modeling.

MSG is Minimum Stable Generation and is expressed as a percentage of a generator's installed capacity.
VOM is Variable Operations and Maintenance costs.
EFORd is Demand Equivalent Forced Outage Rate.

Price forecast error

LEI employs its proprietary production cost model to determine future energy market prices and the effects of projects on those prices over time. This model incorporates certain stochastic elements that cause plants to be forced offline in accord with their forced outage rates. It also distributes maintenance outages across the year in keeping with the historic distribution of maintenance outages allowed by ISO-NE. When a new plant is introduced into the modeling, this outage distribution changes somewhat to accommodate that plant and keep the general maintenance distribution consistent with ISO-NE practice. This maintenance process adjustment, combined with the random nature of enforcing forced outages, creates some randomness to the forward price outlook, which is effectively 'modeling noise.' Therefore a forecast price outcome, once we introduce proposed projects, combines both the effect of the project and the 'modeling noise' discussed above.

We wanted to measure the ratepayer benefits from the project and therefore needed to isolate and then deduct the 'modeling noise.' As a consequence, we performed price forecasting error testing to determine which of these effects are explained by the introduction of the project and which are purely random. This testing involved running certain projects and portfolios over and over again with 30 different random number seeds and then cataloguing the distribution on projected price impacts. We then constructed a confidence interval from this distribution, which then allowed us to distinguish whether the projected annual energy price impact (which were sometimes as low as $0.10/MWh) was statistically significant or not. Where the effects were found to not be statistically different from the baseline, we discarded the random impacts and conservatively used the baseline energy prices instead of the energy price impacts produced by these projects.

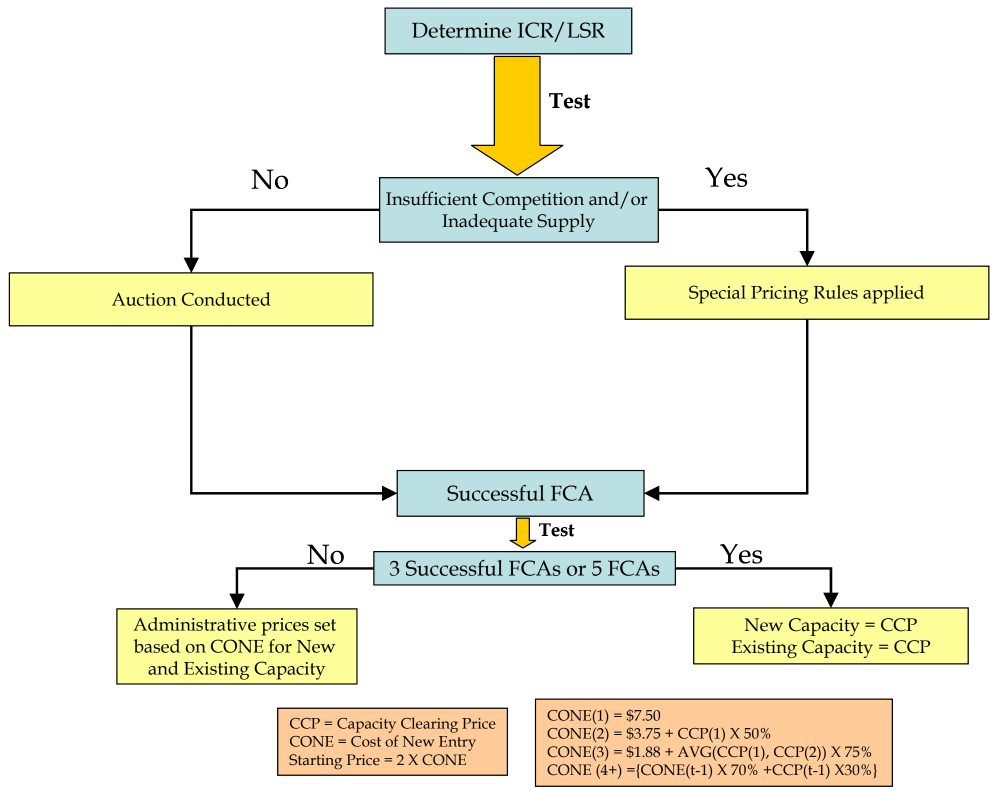
Larger projects were found to produce statistically significant energy impacts, and for these we kept the energy prices that resulted from the modeling, without adjustment. Small peaking projects and demand response were found to not be statistically different from the baseline with a 95% confidence interval. This is not to say, however, that these small peakers and DR projects had no impact on energy prices when combined with other projects into portfolios. Indeed, we determined that when combined into portfolios small peakers and DR projects could have a significant energy price impact and we incorporated them into our measurement of benefits these portfolios are expected to produce.

7.2 Capacity model

The FCM model simulates the capacity clearing price of each Forward Capacity Auction (FCA) using a single-shot auction platform[39] and the rules specified in the Settlement Agreement. The model is set up to simulate separate auctions for each defined import-constrained zone, as necessary. After demarcating the various zones and location of capacity (based on the rules specified in the Settlement Agreement), the model takes the projected bids of qualified capacity (existing and new) and sorts the capacity based on bid price, thereby forming a supply stack. The capacity clearing price is determined at the intersection of the supply stack and the procurement target, the Installed Capacity Requirement (ICR) or Local Sourcing Requirement (LSR). The model has been expanded to take into account the various pricing rules in the Settlement Agreement, including the Cost of New Entry (CONE) calculation, the capacity clearing price floor and ceiling for the initial FCAs, and the alternative pricing rules, as illustrated in the simplified figure below.

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

Figure 29. Flow diagram of capacity modeling pricing structure



Rational behavior and competitive bidding has been assumed throughout the Economic Analysis.[40] Therefore, capacity resources are assumed to bid into the FCA based on the minimum going forward costs. For Existing Capacity, those minimum going forward costs are defined as fixed operations and maintenance costs (FO&M) and interest expense and debt principal repayment (collectively, the debt charge). For New Capacity, the minimum going forward fixed costs will include all fixed costs, including return on equity as well as the debt charge and FO&M. New Capacity will not have committed to development fully until they are awarded a contract in the FCM (i.e., they do not have any sunk costs, in contrast to existing generators), and therefore their avoidable costs are much higher. Once New Capacity clears a FCA, it will be treated as Existing Capacity for subsequent FCAs.

Bids in the FCM model are assumed to be the minimum that a supplier could bid and cover its going-forward fixed costs. Thus, energy profits and LFRM revenues (namely the LFRM

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

premiums) are subtracted from the FO&M of each resource to derive its final bid price.[41] The intersection of the merit order supply stack and the procurement target (ICR/LSR) determines the market clearing price (assuming that the special pricing rules have not come into play).

ICR/LSR forecast

ISO-NE published a ten-year ICR projection. However, it is unlikely that ISO-NE will publish ICR projections that look out over a fifteen-year period, consistent with our modeling horizon. As such, we found it is necessary to forecast our own estimates of procurement targets in the FCM, i.e., the ICR and LSRs. We have relied on all available working group documents from ISO-NE on the evolution of its methodology in order to align our analysis as closely as possible with the inputs used in its Regional Supply Plan. Figure 30 below presents the ICR and LSR projections for nine scenarios.

Figure 30. New England ICR and Connecticut LSR projections for nine scenarios

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
New England															
Scenario 1-4	30,696	31,309	32,029	32,824	33,659	34,410	35,009	35,557	36,051	36,504	36,904	37,278	37,621	37,941	38,236
Scenario 5	30,696	31,309	32,029	32,754	33,543	34,252	34,890	35,455	35,951	36,407	36,854	37,256	37,621	37,941	38,236
Scenario 6, 7	30,446	30,611	31,087	31,565	32,091	32,503	32,772	32,995	33,147	33,279	33,386	33,473	33,545	33,605	33,655
Scenario 8, 9	30,948	31,999	33,017	34,017	35,106	36,108	36,975	37,858	38,655	39,414	40,175	40,982	41,722	42,311	42,849
Connecticut															
Scenario 1-4	6,133	6,285	6,476	6,713	6,923	7,120	7,259	7,383	7,501	7,612	7,716	7,815	7,908	8,013	8,096
Scenario 5	6,133	6,285	6,476	6,673	6,882	7,079	7,259	7,383	7,501	7,612	7,716	7,815	7,908	8,013	8,096
Scenario 6, 7	6,087	6,147	6,311	6,452	6,601	6,735	6,811	6,876	6,920	6,955	6,981	7,001	7,016	7,028	7,037
Scenario 8, 9	6,169	6,419	6,668	6,927	7,198	7,456	7,654	7,877	8,049	8,211	8,363	8,522	8,673	8,818	8,935

7.3 LFRM model

The Locational Forward Reserve Market (LFRM) in the ISO-NE control area is designed to provide a market-based method for procuring non-spinning operating reserves on an ISO-NE system-wide basis. Generators who are awarded a Forward Reserve contract in the Forward Reserve Auction (FRA) get paid a reservation payment to be available to provide 10-minute non-spinning reserves and 30-minute operating reserves. The LFRM model simulates the auction clearing process of each summer season Locational Forward Reserve Auction (LFRA) over the forecast time horizon. Qualified resources are identified and sorted based on their modeled bid price. The LFRM identifies qualified resources based on their technical capability (ramp rate), economic qualification (proxied by an analysis of the strike price (Forward Reserve Heat Rate) and each resource's modeled technical heat rate[42]), and location. The bid price for

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41 Because the FCA occurs nearly three years before the Day-ahead energy market and the LFRM auction, we also discount the energy profits and LFRM revenues by roughly three years to reflect suppliers' uncertainty about actual profits that may be earned in the energy market and LFRM three years out.

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

LFRM-qualified resources is based on minimum going forward fixed costs, i.e., FO&M and debt charge. This bid price determines the supply stack and which resources are awarded a LFRM contract. The auction clearing prices are then a function of the excess supply, as discussed further below. Consistent with current rules with respect to settlement during the Transition Period and anticipated rules for settlement once the FCM starts, the bids that resources offer into the LFRM are net of revenues earned in the FCM.

The Auction Clearing Price is based on the intersection of the LFRM bid stack for each LFR zone and that zone's Locational Forward Reserve Requirement (LFRR). The LFRM model uses this merit order bid stack to determine which plant are able to clear based on their bid price and the procurement target. The actual price, however, calculated by the model is the sum of the LFRM price premium and the FCM clearing price. This price premium reflects the additional costs and risks of participating in the LFRM and that are demanded by market participants such as foregone energy revenues, severe unavailability penalties, etc. We calculate this LFRM price premium by using the implied historic relationship between the supply margin (supply offered into the forward reserves market greater then the reserves requirement) and the ICAP margin (forward reserve clearing prices above the historic ICAP clearing prices). The model then feeds the LFRM revenues (the product of the LFRM price premium and the quantity of supply each generator cleared) into the FCM model to determine the final FCM clearing price. The sum of the FCM clearing price and the LFRM price premium is equal to the full LFRM clearing price.

LFRM price premium

A generator's bid into the LFRM will be made up of it expected costs of participation and foregone revenues that result from its participation at a minimum. If a generator cannot expect to earn additional revenue over and above what it can earn in the FCM (just for being present), then it will not participate in LFRM and will not provide second contingency protection to the system. The "premium" to cover these additional costs and lost opportunities that are inherent in LFRM participation and that are required in addition to FCM payments is referred to as the "LFRM price premium" or "LFRM premium". The final LFRM price is the sum of the LFRM price premium and the FCM clearing price. Testimony provided by Mark Montalvo of ISO-NE states that a supply offer would consist of the following elements:

1. expected foregone energy profits;
2. plus expected foregone commitment costs;
3. plus expected penalties;
4. plus incremental O&M and/or capital investment;
5. plus expected ICAP clearing prices;
6. plus risk premium.[43]

When the expected ICAP clearing prices are subtracted from the above list (as FCM prices will be netted from LFRM clearing prices), the remainder is the LFRM price premium. We have

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43 See February 6, 2006 ISO-NE ASM Phase 2 filing at FERC, Attachment 2, Direct Testimony of Mark D. Montalvo, p. 24.

estimated the LFRM price premium based on the historical premium that has been demanded by forward reserve market participants over and above the historic ICAP clearing price.

The dataset we used for estimating this relationship consists of the individual bid prices of each participant during six separate FRM auctions. The aggregated offer quantities of these participants, together makes up the total quantity offered in each auction. The quantity cleared represents the demand for forward reserves and the quantity offered represents the supply. The ratio of supply and demand is the FRM supply margin. For the same time periods, we also analyzed the FRM clearing prices and the ICAP clearing prices. The difference between these two market clearing prices is the historic FRM price premium. We added some further refinement to this analysis by including detail on whether a resource was an online or offline resource and whether the particular forward reserve auction was for a summer or winter period. The statistically significant relationship that we found (and applied in our annual simulations of the LFRM) is:

FRM price premium = -0.80 * Supply Margin + 2.93 ($/kW-month)
where,
Supply margin = (quantity offered / quantity demanded) - 1

Using this relationship, we were able to calculate the LFRM price premium in each year. Individual LFRM resources were then paid their quantity cleared times the LFRM price premium.

LFRR forecast

Locational Forward Reserve Requirement is the procurement target in the LFRM. In our modeling, we used the ISO-NE's publicly available forecast for CT state and SWCT. Although the benefits of the Phase 2 transmission project may reduce the SWCT LFRR to zero, we have adopted a conservative approach and held the LFRR constant at 550 MW over the forecast horizon for SWCT and at 1,340 MW for Connecticut. Moreover, since SWCT is nested within Connecticut, any resources that satisfy operating reserves requirements in SWCT are also eligible for CT Reserve Zone's LFRR, and this effectively reduces the CT LFRR by an equal amount.

In our analysis, we assessed the LFRM on an annual basis. Hence, we have conservatively assumed the higher of a year's seasonal projected reserve requirement to be approximately equal to the annual reserve requirement. The summary of our forecast for LFRR for CT state and SWCT is shown in Figure 31 below.

Figure 31. LFRR projections for CT state and SWCT (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CT state	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340
SWCT	650	550	550	550	550	550	550	550	550	550	550	550	550	550	550

Summary Report and Results of Analysis
Electric Generation Project Execution Risk

Connecticut Department of
Public Utility Control
September 13, 2006 RFP to reduce impact of FMCCs

DPUC Investigation of:
Measures to Reduce Federally Mandated Congestion Charges
Docket No. 05-07-14PH02

April 23, 2007

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

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

1. Result in the lowest reasonable cost of incremental electric generation capacity products and services;
2. Increase electric system reliability; and
3. Minimize FMCCs to the state of CT over the life of the contract.

For each contract executed with a successful bidder as a result of the RFP process, there will be an associated incremental electric generation or demand side capacity project (Project) which will be developed and/or constructed.

Inland Energy Consulting (IEC) has been retained by the DPUC to assist in the analysis and evaluation of proposals submitted in response to the RFP. An important part of the overall analysis of proposals is a determination of the likely risk associated with the development and execution of each Project. In order for a proposal to successfully meet the 3 requirements of the Act above, the Project underlying each selected proposal must be technically feasible and contain a low enough level of development and project execution risk so that the DPUC is comfortable that proposed time lines, Project performance benchmarks and contractual milestone dates can be met. Thus, this analysis is intended to verify that the selected projects are indeed likely to provide the benefits that are warranted in their proposal and upon which they were selected, thus ensuring that the three priorities of the EIA Section 12 (i) are fulfilled.

This document summarizes the analysis of proposals received in response to the RFP from a technical and project execution risk perspective.

Summary of Financial Bids (proposals):

The table below lists the proposals analyzed. Note: CCCT = combined cycle combustion turbine (a.k.a. combined cycle gas turbine or CCGT), DR = demand response, EE = energy efficiency, SCCT = simple cycle combustion turbine (a.k.a. simple cycle gas turbine or SCGT).

Proposal Code	Type	Generation technology
146	CCCT	2x1 Combined cycle plant repowering existing steam turbine
409	CCCT	Two dual fuel combustion gas turbine generators and one steam turbine generator.
234	DR	Proposed DR technologies include customer curtailment or customer side emergency generation
272	DR	Curtailment strategies, including lighting control, HVAC management, and back-up generation
323	DR	Combined heat & power projects and distributed generation
592	DR	Dispatchable demand response targeted at reducing peak usage
646-A	DR	Load management / curtailment
646-B	DR	Load management / curtailment
358	EE	No loads interrupted, loads only reduced or turned off if not in use
487	EE	Energy Efficiency - through demand side management, energy efficiency
511	EE	Energy Efficiency Projects in the C&I sector consisting of various energy efficiency measures.
934	SCCT	One simple cycle combustion gas turbine plus one smaller base load generator
399	SCCT	Two simple cycle gas combustion turbines
654-A	SCCT	One simple cycle gas combustion turbine
654-B	SCCT	Two simple cycle gas combustion turbines
654-C	SCCT	Three simple cycle gas combustion turbines
776-A	SCCT	One simple cycle gas combustion turbine plus one smaller base load generator
776-B	SCCT	One simple cycle gas combustion turbine plus one smaller base load generator
851	SCCT	Three simple cycle gas combustion turbines
892	SCCT	Two simple cycle gas combustion turbines
951	SCCT	Four simple cycle gas combustion turbines
993	SCCT	Simple cycle gas combustion turbine

Table 1.0. Summary of conforming Financial Bids received in response to the RFP

Methodology:
In order for the objectives of the EIA and the RFP to be met, each Project selected must be completed and must perform within the operating parameters proposed. Project execution risk exposure for each proposal is unique. In the event of a risk driven unfavorable outcome, the value of the risk is a function of the delay in the project's scheduled on-line date, and/or the project's inability to deliver the capacity benefits along with the likelihood that the unfavorable outcome (delay in commercial operation or unsatisfactory Project operation) will occur.

Each proposal was individually reviewed and analyzed in order to identify proposal elements which could introduce either technical feasibility or project execution risk

The focus of this evaluation is NOT to rank individual projects one by one from best to worst as it relates to risk. Rather, IEC evaluated all proposals and placed each one into a "category of risk" which suited the overall structure and schedule for the proposal. Therefore, readers of this documents should not construe a minor difference in risk score as an indication that one project is necessarily "better" than another. As mentioned elsewhere in this document, the primary proposal evaluation metrics within the RFP process include Project reliability, economics and execution risk components. Project execution risk scores therefore, are not a primary differentiator in the overall proposal analysis for the DPUC RFP.

Items considered in the risk evaluation for each project include:

1. Site Control
2. Permitting
3. Development schedule
    a. Equipment order & delivery
    b. Construction
    c. Testing
    d. Commercial operation
4. Fuel supply
    a. Infrastructure – tanks, pipelines, etc.
    b. Backup fuel supply, if any
5. Electric interconnection
6. Generation technology and performance
    a. Heat rate/efficiency
    b. Air emissions
    c. Ramp rates
    d. Proven vs. "new" technology?
7. Progress toward financing
8. Control and measurement systems
    a. For DR and EE, sustainability and verification
    b. For DR and EE, measurement of capacity as dispatched
9. Experience of bidder and EPC contractor

10. Customer marketing and incentive plans (DR and EE)

Wherever necessary, IEC has requested that certain bidders respond to data requests or interrogatories in order to completely define proposal parameters in a way that allowed the risk analysis to be completed. Responses to these data requests have been considered in completing the risk analysis for each proposal.

Findings:

IEC has determined that none of the proposals reviewed are "infeasible" from a technical or risk perspective. Projects that received "high" risk scores, therefore, are not infeasible, but rather, have a high likelihood of experiencing a significant delay in commercial operation date, or may not initially operate as proposed.

As previously discussed, project execution risk will typically manifest itself in the form of schedule delay for electric generation projects. Other unfavorable risk driven outcomes include operation of the completed Project on a timely basis but at levels which are inferior to the proposed and "warranted" levels.

The value of the execution risk and the risk score assigned to each proposal is a combination of both objective measures and subjective observations based on more than 20 years in the electricity industry and based on latest information on industry practices and commercially reasonable standards. Total Project execution risk is a function of:

- The types of exposure to adverse outcomes inherent to each proposal.
- The perceived likelihood that risk exposure will actually result in an adverse outcome.
- The impact of the adverse outcome, if it is triggered, in terms of delay.
- The value of the "lost capacity benefits" to Connecticut rate payers as a result of the adverse outcome.

While none of the qualified proposals which were evaluated were found to be "infeasible" there were aspects inherent to each proposal which comprise its unique overall risk exposure.

Each proposal has been assigned a "risk score". The risk score is a reflection of the likelihood that the proposed Project will experience delay in schedule or will not operate as proposed for a period of time. In general, the risk scores are interpreted as follows:

- Low risk projects = 0 to 3 months delay or deficient operation
- Low to moderate risk = 0 to 9 months delay or deficient operation
- Moderate risk = 0 to 12 months delay or deficient operation
- Moderate to high risk = 3 to 15 months delay or deficient operation
- High risk = 6 to 18 months delay or deficient operation

It is possible and even likely that individual Projects with risk scores in the "moderate" or even "moderate to high" range could be selected for final contract award due to economic benefits inherent to each proposal. In this instance the liquidated damages provisions of the final agreement are designed to compensate the Buyer for project execution risk.

The following table summarizes the risk scoring of each Project.

Proposal Code	Type	Generation technology	Final risk rating
146	CCCT	2x1 Combined cycle plant repowering existing steam turbine	low
409	CCCT	Two dual fuel combustion gas turbine generators and one steam turbine generator.	low to moderate
234	DR	Proposed DR technologies include customer curtailment or customer side emergency generation	moderate
272	DR	Curtailment strategies, including lighting control, HVAC management, and back-up generation	low to moderate
323	DR	Combined heat & power projects and distributed generation	moderate
592	DR	Dispatchable demand response targeted at reducing peak usage	low
646-A	DR	Load management / curtailment	moderate
646-B	DR	Load management / curtailment	moderate to high
358	EE	No loads interrupted, loads only reduced or turned off if not in use	moderate
487	EE	Demand side management and general energy efficiency measures	high
511	EE	Energy Efficiency Projects in the C&I sector consisting of various energy efficiency measures.	high
934	SCCT	One simple cycle combustion gas turbine plus one smaller base load generator	high
399	SCCT	Two simple cycle gas combustion turbines	low
654-A	SCCT	One simple cycle gas combustion turbine	low
654-B	SCCT	Two simple cycle gas combustion turbines	low
654-C	SCCT	Three simple cycle gas combustion turbines	low
776-A	SCCT	One simple cycle gas combustion turbine plus one smaller base load generator	moderate
776-B	SCCT	One simple cycle gas combustion turbine plus one smaller base load generator	moderate
851	SCCT	Three simple cycle gas combustion turbines	moderate
892	SCCT	Two simple cycle gas combustion turbines	moderate
951	SCCT	Four simple cycle gas combustion turbines	low
993	SCCT	Simple cycle gas combustion turbine	moderate

Table 2. Final Risk scoring for conforming Financial Bid Submissions

Review of Selected Proposals:
The selected portfolio of projects consists of proposals #409, #358, #993 and #851. Below are observed strengths and weaknesses of the selected proposals from a technical feasibility and project execution risk perspective.

Proposal #409: Two combined cycle gas combustion turbines (GE manufactured) and one steam turbine.

This project is in an advanced phase of development. The benefit from a risk perspective is that many of the significant uncertainties around prospective generation projects, such as electrical interconnection details, costs and timing and permitting requirements and time lines are largely already resolved in this Project. Electric interconnection studies are complete, and most permits are either obtained or in process.

The GE generation technology to be installed is commonly used in the power generation industry worldwide. The Project location is on an existing 'brown field' industrial site. The Project Engineer is well experienced and the EPC contractor is also experienced, having constructed a number of smaller scale power projects in the USA. The Proposer (Project owner) on the other hand, does not possess significant amounts of related experience and has not demonstrated its ability to manage and complete a project of this scope.

Project schedule milestones appear reasonable and achievable.

On a comparative basis, this proposal was evaluated against only one other technically similar competing proposal from bidder #146. The #146 proposal employed generally similar but a less widely deployed version of GE technology. The permitting and electric interconnection uncertainty for #146 was perceived to be greater than for #409. As a counterpoint however, the #146 bidder has far more experience in developing, constructing and operating this type of project than #409. The #146 proposal was (as proposed) less efficient (heat rate) and exhibited more limited availability overall than #409. Further, proposal #146 required some unique construction (ISO-NE approved shut down for RMR re-powering) and infrastructure (fuel line siting, permitting and construction) aspects that introduced exposure to schedule delay which was not present in #409.

Proposal #358: Energy Efficiency (CT statewide).

This bidder is experienced and knowledgeable. The financing for the project is in place. The capacity is derived from curtailment or replacement of commonly installed appliances such as lighting, air conditioners and electric heating. Bidder's implementation and customer (load) acquisition plans for the program seem reasonable. Schedule intervals are reasonable and should be achievable.

On a comparative basis, this proposal was evaluated against two other similar proposals. One (#487) was significantly larger in capacity and the other was approximately the same capacity (#511). Proposal #487 will require a substantial number (hundreds or perhaps thousands) of new loads to agree to participate in the EE program. From the marketing and customer sales plan information submitted, it was not clear that schedule uncertainty relating to this aspect has been mitigated. Proposal #511, while smaller in capacity than #487, also carried some unique risks. This resource involves adding new participants to an existing EE program. It appears that loads participating in the proposed EE program would have the ability to readily bypass the EE measures making verification and measurement of the capacity derived from the EE program potentially problematic.

Proposal #993: Simple Cycle Combustion Turbine (GE manufactured)

This project is proposed at an existing industrial site. The GE generation technology to be used is relatively new, but is being widely accepted by the power industry and implemented world wide. The owner of the Project is relatively inexperienced, but has assembled a qualified team to engineer construct and operate the Project. The primary risk drivers in this proposal stem from a development and construction schedule which is aggressive and may be challenging to achieve. We remain confident however, that the Project is likely to be constructed as proposed.

There were 7 competing proposals for simple cycle or simple cycle combination generation resources proposed in the RFP. The risk score assigned to this proposal is "moderate". A moderate level of risk is acceptable for a Project such as this one, as long as it delivers attractive economics and is likely to be completed without major adverse outcomes. Even with a "moderate" risk score, IEC believes that it is likely this Project will be completed on time and will operate as proposed. While there were competing proposals with lower risk scores, the economics associated with this Project taken together with its inherent risk level still results in an attractive resource.

Proposal #851: Simple Cycle Combustion Turbines (GE manufactured).

This Project exists now as a "temporary" capacity resource, but is not reflected in the current CELT report as it was scheduled to be removed. Once selected in this RFP, the project will obtain permanent status and permanent permits. Bidder provided assurance that permitting will be simplified since this is only a conversion from temporary to permanent status, rather than a new application. The GE generation technology to be employed is successfully deployed world-wide.

There should be little to no risk related to transmission studies and permanent transmission interconnection being completed. The Project proposes to use liquid fuel as both primary and backup fuel. Tankage is on site for fuel storage, but will be upgraded and expanded when permanent status is obtained. Bidder is experienced with this project (due to successful prior operation and development of the Project as temporary resource), but does not posses a significant amount of other generation development industry experience.

There were 7 competing proposals for simple cycle or simple cycle combination generation resources proposed in the RFP. The risk score assigned to this proposal is "moderate". A moderate level of risk is acceptable for a Project such as this one, as long as it delivers attractive economics and is likely to be completed without major adverse outcomes. Even with a "moderate" risk score, IEC believes that it is likely this Project will be completed on time and will operate as proposed. While there were competing proposals with lower risk scores, the economics associated with this Project taken together with its inherent risk level still results in an attractive resource.

Important disclaimer notice

The DPUC engaged Inland Energy Consulting as a consultant to provide independent detailed technical and risk evaluation support to the DPUC in analyzing the bids received as part of the Connecticut 2006 RFP process and in recommending the portfolio of winning bidders. The analysis detailed in this report is based on data submitted by bidders as of December 13, 2006, the date of Financial Bid Submission as well as subsequent responses to DPUC data requests issued as part of the RFP process. The results provided or opinions put forth in this analysis do not constitute a promise or guarantee as to the occurrence of any future events.

R42-07

Summary of the Transmission Assessment for the Winning Connecticut FCM Portfolio

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Section

1

Summary of Findings

1.1 Introduction

The purpose of these analyses has been to assess the potential and risks for a series of shortlisted generation projects to qualify for the ISO-NE's Forward Capacity Market in the 2010 Commitment Period. Under ISO-NE's FCM, new capacity projects are subjected to a series of transmission related analyses to determine the interconnection viability, and, further, to assess the amount of proposed capacity that may qualify for the Forward Capacity Market. Section 2 contains a discussion of the qualification process.

This report provides an assessment of the transmission related characteristics for the winning generation Proposals. Studies were conducted by Siemens PTI to assess the potential for these shortlisted projects to qualify their capacity for the ISO-NE's Forward Capacity Market (FCM). The analyses were intended to gauge both the capacity deliverability potential of these projects as well as the interconnection risk.

Additionally, Section 1.3 includes a qualitative reliability assessment of shortlisted Demand Response proposals. These projects were qualitatively reviewed for their potential effect at off-loading critical peak flow paths and hence potentially reducing congestion.

1.2 Summary of Findings for Shortlisted Generation Proposals

The winning project to supply base load capacity is Project ID 409. For peaking capacity, the winning proposals were Project IDs 851 and ID 993, respectively. These projects were assessed to be low in risk with respect to both interconnection viability and deliverability of capacity for Connecticut. Through the analyses performed, no overlapping impacts were found that would reduce the qualified amount below its full seasonal capability. Therefore, it is our opinion that these projects should qualify their entire capacity under the ISO-NE's FCM process.

Critical transmission-related factors in the analyses were the favorable location of these facilities within the CT transmission system as well as their favorable interconnection queue priority relative to other proposals. The projects' positioning within key interfaces effectively makes the projects closer to major load centers and reduces deliverability risk. Additionally, the base load project may be well positioned to take advantage of the additional transfer capacity to SW Connecticut through the SWCT Phase I and Phase II transmission projects.

From a reliability perspective, Project ID 409 may provide important incremental capacity within potential constrained transmission interfaces, particularly with a major generation outage. Likewise, Project 851 and 993 may provide critical voltage and capacity support at peak load or under certain contingencies conditions. The overall potential reliability benefits provided by the projects were scored qualitatively on a scale from 0 to 2.5

Table 1 provides a summary of our findings for the shortlisted generation projects.

Project ID	Interconnection and Deliverability Transmission Attributes	Potential Reliability Benefits and Qualitative Score
409	No interconnection or deliverability transmission issues noted. Located "inside" of the potentially constraining CT Import and CT East-West interfaces, resulting in lower deliverability risk. Positioned to utilize SWCT Phase I and II transmission projects.	Potentially important "internal" CT capacity addition for circumstances where the CT Import interface may otherwise not be able to support load. **Score: 2.5**
146	Located east of the potentially constrained CT East-West Interface, resulting in higher interconnection and deliverability risk. Potential market deliverability issues under certain N-1 conditions. Competes with other sources east of the interface.	May provide SE CT voltage support and capacity. If the project operates economically, may help to alleviate RMR payments. **Score: 2.0**
851	No interconnection or deliverability transmission issues noted.	May provide capacity and voltage support under certain N-1 conditions leading for a critical sub-zone. **Score: 1.5**
776	Competes with higher queued generation within area of limited local transmission capacity. Would likely require upgrades to the 115 kV system.	May provide capacity, voltage support and the off-loading of certain facilities *absent* other projects. **Score: 1.0**
993	No interconnection or deliverability transmission issues noted.	May help to provide capacity and voltage support to a relatively generation deficient area as well as help off-load (and support) a North to South 115 kV path. **Score: 1.5**

Table 1. Summary of Findings: Shortlisted Generation Proposals

1.3 Qualitative Reliability Assessment of Demand Response

Siemens PTI was further asked to evaluate the potential reliability benefits for a series of shortlisted Demand Response proposals. The assessment was strictly qualitative in nature. In general, Demand Response may provide important peak load reduction which in turn may help to off-load transmission facilities (including critical interfaces), thereby reducing congestion and energy prices. Demand Response may have the further benefit of reducing or postponing the need for infrastructure to meet peak load.

In general, projects were assigned a qualitative reliability score largely based on the amount of peak load reduction in the proposal coupled with its potential locational benefits. Demand Response projects were weighed against each other and not relative to the generation proposals.

Table 2 provides a summary for the shortlisted Demand Response proposals.

Project ID	Potential Reliability Benefits	Qualitative Score
272	Large aggregate amount of load. Appears to be mostly located "inside" of the potentially constraining CT Import and CT East-West interfaces, including high demand locations. May help off-load these interfaces, support voltage and reduce congestion and prices.	2.50
592	Large aggregate amount of load. Appears to be mostly located "inside" of the potentially constraining CT Import and CT East-West interfaces, including high demand locations. May help off-load these interfaces, support voltage and reduce congestion and prices.	2.50
646-A	Moderate aggregate load amount. Appears that most demand reduction is within beneficial locations	1.25
234	Moderate aggregate load amount. Demand reduction is within a potentially, highly favorable location.	1.75
358	Relatively small aggregate load amount.	0.10

Table 2. Summary of Qualitative Reliability Assessment of Demand Response Projects

Section

2

Model Development, Criteria & Study Methodology

2.1 ISO-NE's FCM Qualification Process for New Capacity

Under ISO-NE's FCM, new capacity projects seeking to qualify for the Forward Capacity Auction (FCA) for the 2010 Commitment period are subject to two distinct transmission related studies. These assessments are described in the ISO-NE Planning Procedure Document 10 (PP-10). The first aspect is described as an "Initial Interconnection Analysis". The Initial Interconnection Analysis portion is focused on identifying potential upgrades that may be necessary for the project under the ISO-NE Minimum Interconnection Standard (MIS). The Initial Interconnection Analysis, however, does not bypass the need for a full System Impact Study (SIS) prior to interconnection. Proposed projects with a completed SIS are not subject to this portion of the FCM qualification process.

The second test determines the amount of capacity to be qualified and is described in PP-10 as "Overlapping Impact Analysis". The Overlapping Impact Analysis is specific to the FCM and is designed to test the "deliverability" of the project's capacity to the market. This portion of the analysis determines the amount of project capacity that may qualify for the FCM, while taking into account the overlapping deliverability effects of other projects.

An important criterion for these analyses is that the ISO-NE interconnection queue positions are to be honored in full. That is, the queue determines the order upon which capacity projects are added to the system model for the FCM qualification analysis. As such, the interconnection queue position of any given project is an important influencing factor on its viability.

2.2 Model Development

Studies were conducted utilizing a 2010 summer peak network model provided to market participants by ISO-NE on their web site. This model includes the completed SWCT Phase I and Phase II Transmission Projects. While a number of baseline problems were noted with this case, these were judged to be localized issues that would not impact the primary assessments. Additionally, a number of generation plants were be modified to conform to their seasonal capability. The ISO-NE also provided an official list of contingencies to be assessed.

2.3 Criteria

The study was performed in accordance with the N-1 thermal overload reliability criterion which requires that all transmission equipment, transformers and transmission lines will operate within their long term emergency thermal limits immediately after a disturbance involving the loss of a single transmission element, but without operator intervention. Per criteria, the N-1 transmission condition was supplemented with the assumption of the largest unit out of service in Connecticut. As needed, projects were further tested under N-1-1 conditions, particularly as they may apply to interconnection risk. This criterion includes the N-1 conditions plus the addition of a critical transmission facility out of service. Additionally, effective forced outage rates and demand response at peak load were incorporated where deemed appropriate as sensitivities.

2.4 Study Methodology

The focus of the simulations performed were to assess the “overlapping” impacts affecting the shortlisted projects in order to estimate the amount of qualifying capacity for the projects, and, to an appropriate level, interconnection viability. In lieu of specific capacity amounts, however, the shortlisted projects have been assessed on a risk basis. This is necessary, in part, due to the lack of known specifics with respect to the ISO-NE’s own analysis (which is not public, nor known to have commenced at this time).

The “Overlapping Impacts” were assessed by adding sequentially, in queue order, proposed Connecticut interconnection projects. Simultaneously, efforts were made to maintain a high level of CT imports to reflect the operationally uneconomic nature of some of the existing SWCT generation sources. Additionally, the largest Connecticut generator, Millstone #3, was assumed to be out of service as a sensitivity for much of the analyses. It was deemed, via engineering judgment (as well as codified criteria), that this outage represents conditions most related to the need for incremental capacity to serve Connecticut load. Aside from the Millstone #3 outage, as new Connecticut sources were added to the model, the new resources were dispatched against both older SWCT resources as well as sources from northern New England.

It should be noted, however, at the time of this writing, interface transfer limits and allocation of tie-benefit capacity over the key interfaces are unknown. These limits and allocations, when determined, will be utilized by the ISO-NE for its analysis. In order to estimate the potential effect of “reserved” tie-benefit capacity and inter-zonal transfer limits, projects were assessed with a dispatch resulting in reasonable inter-ISO imports and a high level of Connecticut Import.

Further, all analysis was conducted assuming the SWCT Phase I and Phase II Transmission Projects are in service for the summer 2010 peak. It is our understanding that this will likewise be a condition for the ISO-NE analysis. As such, the results of this assessment may not apply to a situation where these projects are not yet in service.

2.5 Note with respect to information availability

It is important to note that the analysis performed was not intended to be as comprehensive or rigorous as traditional interconnection studies or the proposed overlapping impact analysis. The ISO-NE, at the time of this writing, has not yet published information relevant to this assessment such as transfer interface limits, inter-area tie benefit flows nor the dispatch conditions constituting “reasonable” or “stressed” conditions. However, referencing PP-10 as a guideline, in conjunction with engineering judgment, the intent has been to capture the salient issues at hand (that is, to assess the capacity qualification risk associated with each project given available information).