

CAPACITY WATCH

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EXECUTIVE SUMMARY

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In this issue of *Capacity Watch*, ESAI looks more closely at how new power plants will get built in the Northeast markets over the coming years. Conventional new build developers are increasingly relying on long term PPAs with LSEs to achieve their project's economic targets. Such economic targets do not appear achievable in the merchant markets. This begs the question of whether capacity market are still relevant to the needs of the marketplace. Further, an assessment is made regarding the potential for capacity markets to evolve such that socially acceptable outcomes are achieved, providing incentives for the types of resources that are relevant to local, state and ISO goals.

This issue of *Capacity Watch* reflects collaboration between ESAI and Charles River Associates (CRA), under which senior CRA analysts have provided targeted contributions, high-value insight and additional input into this ESAI report. This joint effort is designed to deliver additional value to ESAI's Northeast Power Service clients through the breadth of our combined perspectives. Please note ESAI and CRA remain unique organizations dedicated to their respective client bases.



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As discussed in ESAI's September *Energy Watch Quarterly*, there is little opportunity to progress new merchant generation construction in the Northeast. Capacity market clearing prices in each of the three Northeast pools are projected to be far below that needed to support new entry into the markets. Shortfalls in both capacity and energy revenues are resulting in net present values for generic combined cycle plants that are below \$500/kw in both PJM and New England. This compares with estimates for new build costs at close to \$1,100/kw.

There are many challenges to building new conventional combined cycle or simple cycle power plants on a merchant basis. Merchant revenue projections are clearly not enough to support a new project in almost every area in the Northeast. With the addition of major transmission upgrades in New England and PJM, there are few load pocket niches left to exploit – the most significant ones being New York City and Long Island. Even if a bullish developer was anxious to push forward a new project, there are no financial institutions willing to underwrite a merchant project in the current environment. The uncertainties associated with carbon legislation, competition from renewables, and load reduction due to energy efficiency programs all add to the hurdles set before merchant developers.

High prices and new regulations in markets often spawn new and competitive solutions or technologies. Until the recent drop in gas prices, the low cost of coal and the high price of gas were fueling interest not only in renewables but in base-load coal technologies such as IGCC (Integrated Gasification Combined Cycle) and IGCC with CO₂ sequestration. This technology turns coal into a clean synthetic gas that is then used as the fuel source for a combined cycle plant. Combining this technology with removal and sequestering of CO₂ appears to be a brilliant technological solution to exploiting a rich coal resource and meeting environmental goals.

Two very significant problems present themselves for IGCC projects. Firstly, these projects are very expensive and must rely on a very wide gas to coal spread to be economic. The current gas to coal spreads are much too narrow to support an IGCC project in the merchant arena. Secondly, the technologies (and associated costs) for CO₂ sequestration are unproven on a commercial scale and the current risks for a developer on cost and performance are too high to proceed on a merchant basis. The question is whether regulated entities will pursue these technologies in an attempt to kick start technological progress on these issues. So far, most IGCC projects have been shelved or delayed including perhaps the most promising in the Northeast – AEP's 600 MW Mountaineer project in Mason County, West Virginia.

The drivers for renewable energy projects are still intact although weakened somewhat. Gas prices are the main driver for energy prices in the Northeast and the recent drop in gas and associated energy prices has hurt the revenue outlooks for most renewable projects. Higher prices for Renewable Energy Credits (RECs) are making up some of the difference, but only if the energy and RECs can be sold under long term contracts. So far, renewable developers in New England have been

successful in selling their renewable energy under long term contracts. In New York, developers have the option to contract with NYSEERDA or export to other regions such as New England. Wind energy development continues to be strong in western PJM where high capacity factors help to offset the lower energy prices.

Renewables Are the Exception

Renewable energy projects with low capacity factors such as wind and small hydro do not rely heavily on capacity markets for revenue, in fact, many developers will ignore capacity revenues in their proformas and will count these revenues as upside if they materialize. Higher capacity factor projects such as biomass and landfill gas will want to include capacity revenues as a more significant portion of their revenue base. Although renewable energy sources tend not to rely heavily on capacity revenues, their increasing presence – even at low capacity factors – will begin to weigh heavily on capacity markets. In this regard, the percentage of renewable nameplate capacity that qualifies for capacity markets can make a difference. In PJM for example, only 13 percent of wind nameplate capacity will qualify capacity due to the low expectations for wind output during super-peak hours.

Renewable energy projects will continue to get built regardless of the capacity market outlooks. State and possibly federal mandates will keep the REC markets robust. If energy prices are low, then higher REC prices can be paid to make any specific project economically viable. High fuel prices will only increase the incentives for new renewable construction. Due to the general shortfalls in REC supply, especially in New England, renewable development is likely to be robust over the next ten year time horizon.

With the addition of increasing amounts of wind capacity to the system, more fast responding gas capacity will be needed to manage the system. But in the face of daunting economic and regulatory challenges, how will new conventional power plants get built to sustain the reliability needs of the power pools?

RFP SUPPORTED NEW BUILD

The large majority of the new conventional technology construction in New England and New York has recently been supported by long term PPA contracts that resulted from LSE issued RFPs. In the case of Connecticut Light and Power, their RFPs for new capacity were originally promulgated at the state level. In New York, RFPs issued by LIPA, ConEd and NYPA have resulted in long term contracts that have supported the Neptune DC cable, Astoria Phase I and II, Caithness Energy, and potentially the Hudson Transmission Partners project. However, the Linden VFT and the Besicorp Empire projects were developed on a merchant basis and they were able to secure tolling contracts from the marketplace. The Besicorp Empire project secured its tolling/long term hedge positions at a time when forward spreads supported the project. The drop in gas prices has resulted in lower spark spreads that are no longer supportive for this type of project. Looking forward, it is likely that conventional generation development in New England and

ARE CAPACITY MARKET FUNCTIONS STILL RELEVANT?

The principal intentions of implementing capacity markets in Northeast have been two-fold: to provide the right incentives to get new generation built in the locations where it is needed for resource adequacy, and to retain efficient existing generation and encourage retirement of resources that are no longer economic. But, as discussed in the prior section, new generation is increasingly being funded by mechanisms outside of the capacity markets. Hence, the question arises: are capacity markets still relevant and what are their functions?

If all new generation is funded by sources outside of the capacity markets, will capacity markets become simply a payment system for existing generators? And if so, what are the appropriate levels of those payments. One potential outcome is that while all or most new capacity comes in through other mechanisms, capacity markets remain and are designed to send price signals consistent with new entry when it is needed. Under this scenario, the markets would produce observable prices that could guide the bilateral and RFP-based contracts for non-market new generation. Such a market would also be consistent with the theory of an efficient, single-price auction, as existing generators would receive the same payments as new units. However, crafting rules that produce such price signals, especially in an environment when the actual prices for new entry are often negotiated behind closed doors or through sealed-bid processes, is difficult to achieve.

Capacity markets may be relevant in other ways. Can the market be adapted to provide the right payments to the generation resources most valuable to the system? If so, even with new generation coming largely or entirely outside of the market, capacity market price signals would provide valuable information, sending the right signals to plants that should be retired, and providing fair compensation to those that are economic to keep in operation.

CAN CAPACITY MARKETS PRODUCE SOCIALLY ACCEPTABLE OUTCOMES?

Are the current capacity markets keeping up with evolving needs? Recent discussions in New England and elsewhere call into question the fundamental construct of capacity markets. The capacity markets in place today are narrowly focused: securing enough resources to meet the planning reserve margins both system-wide and in (typically large) load pockets. In these designs, megawatts of capacity are undifferentiated, one from another; a renewable MW is no different than a nuclear MW, a combined cycle MW, or a demand response MW. In principle, the capacity markets augment the price signals from other markets—energy, ancillary services, RECs, emissions credits, and the like—to guide decisions for new investment in generation and transmission. Collectively, these markets work together to steer the capital stock towards an optimal mix of resources.

And yet, notwithstanding the fact that capacity prices everywhere in the region are below the full cost of new generation, we see new capacity resources coming

PJM RPM TARIFF CHANGES

In response to FERC orders of March 26 and August 14, 2009, PJM has filed tariff modifications that cover a number of important changes to the RPM rules and procedures as outlined below:

1. CONE Determination

PJM has revised the methodology for determining CONE (Cost of New Entry). The Handy-Whitman Index will be used to make year-on-year adjustments to CONE. After every fourth auction, an assessment of recent BRA auction offers will be used to assess whether actual offers are in line with the Handy-Whitman Index. If the assessment is more than ten percent out of line with the index, then PJM will review with stakeholders and propose an alternate CONE value for the next auction. The index will then again be used for the subsequent three auctions, after which a new auction assessment will be undertaken.

2. Conditional Incremental Auction

A conditional incremental auction can be run if PJM determines that it is necessary to secure additional capacity as a result of a delay in a backbone transmission project. This would not apply to transmission upgrades that do not have a 'backbone' designation.

3. New Entry Price Adjustment (NEPA)

New entrant pricing rules have been modified to provide more revenue certainty. A qualified new entrant can receive a three year price assurance under certain conditions. Under previous rules, a new entrant that cleared in its first auction was required to offer in the second auction at its first year bid or 90 percent of CONE, whichever was lower. The new entrant would only get paid if it cleared in the second auction. The rule is being revised such that if the new entrant clears in the second or third auction, it get its price, but if it does not clear, then PJM resubmits the new entrant's offer price. This resubmittal would lower the new entrant offer to a price that would displace just enough capacity to clear the new entrant as the marginal or highest priced unit. This price would be just below the price of the now displaced units.

4. 2.5 Percent Holdback for Incremental Auctions

In compliance with FERC directives, PJM has instituted a 2.5 percent holdback from the Base Residual Auction (BRA) as a reserve purchase in the incremental auctions. This 2.5 percent holdback was instituted in the most recent 2012/13 BRA. The original intent was to spread the 2.5 percent purchase evenly over the three incremental auctions. The new rule provides that 20 percent of the total 2.5 percent would be purchased in

each of the first two incremental auctions and 60 percent purchased in the last incremental auction (0.5, 0.5 and 1.5 percent). This allows greater flexibility for resources such as demand resources that are more likely to enter the last incremental auction that is closest to the coming capability year.

5. Existing Demand Response Can Set Price

To date, existing demand response resources have not been allowed to set price and have been forced to offer into the auctions as price-takers. The new tariff changes specify that existing demand resources can offer in according to their own economic parameters. Further, since demand response participation is voluntary, they will not be subject to price mitigation for high offers.

CONE DETERMINATION

Through the Capacity Market Evolution Committee (CMEC) and other market committees, PJM stakeholders developed a number of proposals to revise the determination of CONE but were unable to reach the required majority for any proposal. Four proposals were placed before the Markets Committee on August 25 but none passed. The four proposals had two common elements:

- Elimination of the current empirical CONE.
- Introduction of the Handy-Whitman Index that would be the basis for an annual CONE adjustment; specifically the “Index of Public Utility Construction Costs”.

The Handy-Whitman index tracks construction costs for combustion turbines in various regions of the country, including regions applicable to PJM. The previous CONE would be adjusted by the percent change indicated by the change in the Handy-Whitman index and the new CONE would be posted along with the other relevant RPM auction data posted prior to the upcoming BRA. This process would replace the three year review of construction costs by an independent consultant.

In addition to the annual index adjustment, PJM will conduct a review of actual auction results including cleared and uncleared offers after the fourth auction utilizing the Handy-Whitman index is completed. PJM will take a comprehensive approach to assessing BRA offers to determine a market reflective CONE. If the result of this assessment is more than 10 percent different than the result indicated by the Handy-Whitman index adjustment, then PJM will review the results with shareholders (by September 1st) and subsequently file a new CONE with FERC by December 1st in order to comply with deadlines consistent with the upcoming BRA auction.

Supplemental to its own review of BRA auction results, PJM will commission a third party independent study of the relevant combustion turbine construction costs for the upcoming BRA. The results of this study are not intended to be bind-

NEW YORK CITY PRICE MITIGATION

In the June 2009 *Capacity Watch*, ESAI provided details of the New York City mitigation rules that apply both to upside price mitigation of high sell offers and downside price mitigation of offers from uneconomic new entry. To prevent high prices that could result from economic withholding, all suppliers with 500 MW or greater will be mitigated at the demand curve (treated as price takers). In addition, they must offer all available capacity into the spot auction.

To prevent new uneconomic entry, a price floor of 75 percent of net CONE will be implemented that will prevent new entrants from pushing the price below the floor. The mechanics of the price floor are fairly straightforward. If there is 300 MW of 'headroom' available above the price floor, then a new capacity resource of 500 MW would clear 300 MW at a price equal to the floor and the remaining 200 MW of the new capacity would not clear. The 200 MW that does not clear is not eligible to be used to meet any New York capacity obligations or in any New York bilateral transaction.

The tariff does not explicitly denote what would happen if two or more new entrants offer into the market and the price floor is triggered. However, it is assumed under these conditions that standard tie breaker rules would apply. The tie breaker rule would stipulate that the 300 MW of headroom in the above example would be prorated between the two or more new entrants that would be clearing at the floor.

This is an important distinction from how the duration of the floor is calculated for a particular new entrant. The first new entrant is mitigated until load growth makes up the difference for the amount of capacity that initially does not clear. In the above example, a 500 MW resource would clear 300 MW in the auction, leaving 200 MW that would not clear. If New York City load growth were 90 MW per year, then the 200 MW would be divided by the 90 MW load growth and a time period of 2.22 years would apply. Since this encompasses four six-month capability periods and part of a fifth, the mitigated price floor would apply to this unit for five capability periods (2.5 years).

If a second resource were to enter the market a few months later, then it would undergo the same time duration calculation, however, its clock would start at the completion of the mitigated time duration of the first unit. For example, if a 300 MW unit entered the market after the first 500 MW unit and the same 90 MW of load growth were applied, its time duration for floor mitigation would be seven capability periods ($300/90 = 3.33$ years). This 3.5 year period would start at the end of the 2.5 year period that is applied to the 500 MW. Thus the second 300 MW unit would be subject to the floor for 6.0 years or twelve capability periods.

NEW RESOURCE OUTLOOK

The 325 MW Caithness Bellport project on Long Island achieved commercial startup in August and now represents the most efficient capacity on Long Island. The Linden VFT has been delivering energy from PJM to New York City under test conditions and is now expecting commercial startup on November 1, one month ahead of schedule.

In the appendix, ESAI provides an overview of each major project in the New York queue. Notable near term projects include the Besicorp-Empire project, a 620 MW combined cycle plant scheduled as a new entrant into the Rest of State market. The Empire project is located outside of Albany and is expected to start up in September 2010.

As noted above, the Linden VFT is expected to be commercially on-line November 1 and will transfer energy from Linden NJ to Staten Island in New York City. In late 2009. This will be the first increment of capacity added to Zone J since the startup of the SCS Astoria Phase I project in May 2006. Our New York City capacity outlook remains mostly unchanged and is provided below:

Linden VFT	300 MW	November 1, 2009
Poletti Steam Unit Retirement	(891) MW	End January 2010
SCS Astoria Phase II	550 MW	June 2011
Hudson Transmission Partners Phase I	400 MW	June 2012
Hudson Transmission Partners Phase II	260 MW	June 2013
TBD	500 MW	June 2024

Due to the low load growth estimates as provided in the most recent Gold Book projections, the next increment of capacity after the Hudson Transmission Partners project would be in June 2024.

Another plant to highlight is the Coop City (Riverbay) 40 MW cogen under construction in the Bronx. This plant has been on our list, but not included in our capacity and energy models. Because it is not in the NYISO queue, it is being treated as a behind the meter generator. Coop City previously had a steam unit providing power to their load. This plant is expecting startup by January 2010. Some excess power may be sold into the grid.

CALCULATING THE MITIGATION DURATIONS

To calculate the time duration of the mitigated status of the SCS Astoria II and HTP projects, the projected load growth is utilized along with the unforced capacity of each unit (UCAP). If the SCS project assumes a 5.0 percent EFORD, then the 550 MW ICAP capacity translates to about 525 MW. In 2011, ESAI's capacity model indicates that approximately 295 MW of the Astoria II project will clear, leaving 230 MW of mitigated capacity. According to the Gold Book load projections, the summer 2011 peak load will be 12,065 MW and the 80 percent

ISO-NE held the 2012-2013 Forward Capacity Auction (FCA3) on October 5-6, 2009, which as expected cleared at the floor price of \$2.951 per kW-month. Preliminary information from ISO-NE indicates that the auction purchased over 4,400 MW of resources in excess of the Installed Capacity Requirement (ICR) purchase requirement. The excess resources purchased results in preliminary pro rated prices of \$2.535 per kW-month for Rest of Pool resources and \$2.465 per kW-month for resources in Maine. All de-list requests were approved (over 800 MW) except for Dominion's Salem Harbor Units 3 and 4 (580 MW total) which were rejected for reliability reasons, primarily because of the relationship between these units and the import limits into the Boston area. ESAI provides a preliminary discussion of the Salem Harbor de-list issue and the pro rationing of the Maine price later in this section.

The section immediately below contains an analysis of the resources qualified to participate in FCA3 that was prepared prior to the October 5-6 auction and released in ESAI's September 28 *Capacity Watch* Special Report. We provide the analysis once again as an informational service to our clients. ESAI's December 2009 *Capacity Watch* will include a full analysis of the results of FCA3 based on data to be released by ISO-NE in late October. Additional analysis and FCM forecast information is provided at the end of this section.

RESOURCES QUALIFIED TO PARTICIPATE IN 2012-2013 FCA

On October 5-6, 2009, ISO-NE will hold its third auction under the Forward Capacity Market (FCM). The third Forward Capacity Auction (FCA3) will procure capacity requirements for the June 2012 through May 2013 commitment period. As done in prior issues of *Capacity Watch*, ESAI has performed an extensive analysis of the resources qualified to participate in FCA3. The auction will once again feature a considerable surplus of resources that will drive the clearing price down to the auction floor of \$2.95 per kW-month, calculated as 0.6 times the FCA3 Cost of New Entry (CONE) of \$4.92 per kW-month.

The impact of the resource surplus on the clearing price is magnified by the large amount of price-taking and low offer price resources in the auction. Under FCM, existing resources must be price takers in the auctions, and only certain categories of new resources can offer relatively higher prices in the auctions. Categories of new resources are:

1. New resources electing 'New' treatment (can offer competitively);
2. New resources with qualifying offers below $0.75 \times \text{CONE}$ (low price offers); and
3. New resources deemed to be "Out of Market" (price takers).

As discussed below, FCA3 will feature a large amount of price taking and low-price resources well in excess of the capacity to be procured in the auction – an excess of more than 11,000 MW above the Installed Capacity Requirement (ICR).

TABLE 1 - NEW ENGLAND ICR ANALYSIS						
	2011-2012		2012-2013		CHANGE	
	MW	Reserve Margin	MW	Reserve Margin	MW	Percent
Forecast Peak Demand (50/50)	29,405		29,020		(385)	(1.3%)
Assumed Existing Resources (incl. HQICCs)	35,667		39,293		3,626	10.2%
Installed Capacity Requirement (ICR)	33,439	13.7%	32,879	13.3%	(560)	(1.7%)
HQ Interconnection Capability Credits (HQICCs)	911		914		3	0.3%
NET ICR (to be purchased in FCA)	32,528	10.6%	31,965	10.1%	(563)	(1.7%)
Locational Sourcing Requirements (LSR):						
Connecticut	6,817		6,640		(177)	(2.6%)
NEMA/Boston	2,016		2,019		3	0.1%
Maximum Capacity Limit (MCL):						
Maine	3,395		3,257		(138)	(4.1%)

Capacity to be Purchased in FCA3

ISO-NE has established an Installed Capacity Requirement (ICR) for 2012/13 of **32,879 MW** including Hydro-Québec Interconnection Capability Credits (HQ ICCs), which equates to an installed reserve margin of 13.3 percent. Excluding HQ ICCs of 914 MW leaves a Net ICR of **31,965 MW** to be procured in the FCA. The 2012/13 ICR values are 560 MW (gross) and 563 MW (net) lower than the 2011/12 values. A comparison of 2011/12 and 2012/13 ICR values is provided in Table 1.

The primary driver behind the decrease in ICR was a drop in the peak demand forecast for 2012/13. A comparison of the load forecasts used to determine the 2012/13 values (the Regional System Plan (RSP) 2009 forecast) versus the 2011/12 values (RSP 2008) reveals a drop in forecast peak demand for 2012/13 of almost 400 MW.

ISO-NE also set Local Sourcing Requirements (LSR) for the Connecticut (CT) load zone at **6,640 MW** and for the Northeast Massachusetts/Boston (NEMA/Boston) load zone of **2,019 MW**. As in the prior two FCAs (2010/11 and 2011/12), FCA3 will not have separate clearing prices for NEMA/Boston and CT zones. Thus, the 2012/13 auction will be a two-zone auction with all of New England (including CT and NEMA/Boston) designated as “Rest-of-Pool” and Maine designated as an export-constrained zone subject to a Maximum Capacity Limit (MCL).

The Connecticut LSR is 177 MW lower than the 2011/12 value, which is primarily the result of the large amount of excess supply that cleared in Connecticut in the 2011/12 FCA and a lower peak load forecast assumed for Connecticut. The NEMA/Boston LSR is virtually unchanged as compared to the 2011/12 value. The NEMA/Boston zone had a relatively smaller excess of supply that cleared in the last auction, and ISO-NE’s peak load forecast for NEMA/Boston is slightly higher for 2012 than 2011.

ISO-NE established a Maximum Capacity Limit for capacity in export-constrained areas, which for FCA3 remains as the Maine load zone. The Maine zone would have an MCL of **3,257 MW**, which is lower than the 2011/12 value as a result of lower peak demand forecasts.

33 PERCENT RENEWABLES

California's fascination with renewable energy remains an important topic from the top of state government and on down. The legislature passed bills that would require all utilities, IOUs and POU's, to use renewable energy to meet 33 percent of their total energy sales by 2020. Conditions in the bill such as limiting qualifying renewables to in-state resources would have made achieving the 33 percent goal even more unlikely. As a result, the governor vetoed the bills and instead issued an Executive Order requiring the Air Resources Board to implement the 33 percent standard through its GHG reduction authority and to do so in conjunction with the other regulatory agencies, the California Public Utilities Commission (CPUC) and California Energy Commission (CEC). To further the effort, California has entered into a Memorandum of Understanding with the US Interior Department to develop a process for expedited siting of renewable energy projects on federal land in California. This is important because much of the proposed renewable generation in California would be located on federal land and the overlapping environmental review process could result in delays that would make it difficult to start construction by the end of 2010 – a requirement for the 30 percent Federal Tax Credit.

Transmission Access for 33 Percent RPS

Now that the 33% RPS requirement has been formalized, the implications and costs of achieving it are getting more attention. The CAISO has developed a "2020 Renewable Transmission Conceptual Plan" to identify transmission upgrades that would be needed to deliver the CAISO's best guess of likely renewable resource development scenarios. The resulting upgrades would cost over \$11 billion and deliver about 55,000 GWh/year of renewable generation to load centers. Transmission upgrade costs (by renewable resource zone) are itemized in the table on the following page.

Table 1 - Transmission Upgrades, CAISO

CREZ	MW	GWh	Tx cost (M\$)	Tx \$/MWh*
Tehachapi	4,500	11,565	2,400	\$31.13
Pisgah	3,500	8,995	551	\$9.19
Imperial South**	2,000	5,140	1972	\$57.55
Carrizo South	1,000	2,570	153	\$8.93
Solano***	900	2,313	100	\$6.49
Mountain Pass	1,200	3,084	145	\$7.05
Santa Barbara	120	308	0	\$ -
Carrizo North	600	1,542	140	\$13.62
Round Mountain	187	481	120	\$37.42
Palm Springs	770	1,979	0	\$ -
Riverside East	3,000	7,710	1411	\$27.45
Kramer	2,200	5,654	635	\$16.85
Imperial Valley North	720	1,850	500	\$40.54
San Diego South	678	1,742	270	\$23.25
PG&E Backbone			140	
SCE Backbone			1260	
SDG&E Backbone			1259	
Total	21,375	54,933	11,056	\$30.19

* \$/MWh based on annual revenue requirement of 15% of cost of transmission upgrade.

** Includes Sunrise

*** Upgrades part of Large Generator Interconnection Process (LGIP)

Renewable Integration

The other aspect of the CAISO's analysis of the 33 percent RPS involves the impact of so much intermittent wind and solar PV generation on grid reliability. Part of that study is to evaluate the ability of the existing generation fleet to manage both a 20 percent and a 33 percent RPS. The analysis is expected to be completed in early 2010.

ESAI evaluates individual projects through development and construction and then projects the probability of completion and start-up dates under its Project Evaluation Program (PEP). The projects are then compiled to provide a forecast of new capacity for each year in each of the three Northeast Control Areas. A spreadsheet provides details of each project and is available for specific clients. This spreadsheet can be downloaded from the ESAI website. An abbreviated sample of the spreadsheet is provided below.

ESAI continually updates the PEP as new information becomes available that would affect the timing or probability of completion of a project. ESAI incorporates a wide array of source information to develop an assessment of the likelihood of a project moving forward to completion including:

- Industry Network of Contacts
- Government Agency Contacts
- Financial Community Contacts
- Filings with Transmission Authorities
- Filings with Siting Commissions
- Environmental Permits and Filings
- Municipal Planning, Zoning & Inspector Contacts
- Other; Media & Corporate Relations

These sources, combined with ESAI’s in-house expertise, allow ESAI to provide its clients with detailed and accurate information. ESAI closely follows changes in permitting and siting status and makes adjustments whenever necessary. ESAI also monitors funding qualifications – a key development in the post-Enron environment. The following pages provide a recap of the updates as well as the summarized projections for each Control Area.

ESAI		PROJECT EVALUATION PROGRAM							
		High Confidence	Unconfirmed	Withdrawn	Online	Retirement			
<i>PJM Projects</i>		Developer	Pricing Zone	Fuel Type	Capacity (MW)	Peaker (1)	Probability of Completion	Estimated In-Service Date	Year
Fowler Ridge Wind Farm Phase I	BP/Dominion	AEP	Wind	400		100%	Mar-09	2009	
Cumberland, Millville	Conectiv Energy	AECO	Nat gas	100	1	100%	Jun-09	2009	
Locust Ridge II	Iberdrola Renewables	PPL	Wind	102		100%	May-09	2009	
Highland (Krayn) Wind Farm	EverPower Renewables	PENELEC	Wind	62		100%	Q2 2009	2009	
North Allegheny Wind Farm	Duke Energy	PENELEC	Wind	70		100%	Oct-09	2009	
Ladysmith Unit 5	Dominion	DOM	Nat gas	150	1	100%	Apr-09	2009	
EcoGrove Wind	Acciona Energy	COMED	Wind	100.5		100%	Aug-09	2009	
Grand Ridge Energy Phases II & III	Invenergy	COMED	Wind	100.50		100%	Sep-09	2009	
Delta Power Plant	Conectiv Energy	PECO	Nat gas	545		100%		2011	
Dresden	AEP	AEP	Nat Gas	580		100%		2013	
Susquehanna Uprate Unit 1	PPL	PPL	Nuclear	159		100%		2010	
Susquehanna Uprate Unit 2	PPL	PPL	Nuclear	159		100%		2011	
Longview	GenPower	APS	Coal	695		100%	Mar-11	2011	