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Assessment of Offshore Wind Power Resources

Prepared for:

Long Island Power Authority

August 22, 2007

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EXHIBITS

EXECUTIVE SUMMARY

Pace Global Energy Services, LLC ("Pace Global") was commissioned by the Long Island Power Authority ("LIPA") to assess the assumptions and economic impacts of FPL Energy's ("FPLE") proposed offshore wind power project (the "Project").[1] In this assessment, Pace Global was tasked with the following:

Task 1. Analyzing the cost estimates offered by FPLE and opining on their reasonableness,

Task 2. Performing a financial analysis to evaluate the costs of the Project relative to:

a. Projected marginal power prices at the wholesale level in Long Island (New York Independent System Operator ("NY-ISO") Zone K),

b. Conventional generation alternatives, and

c. Other renewable alternatives.

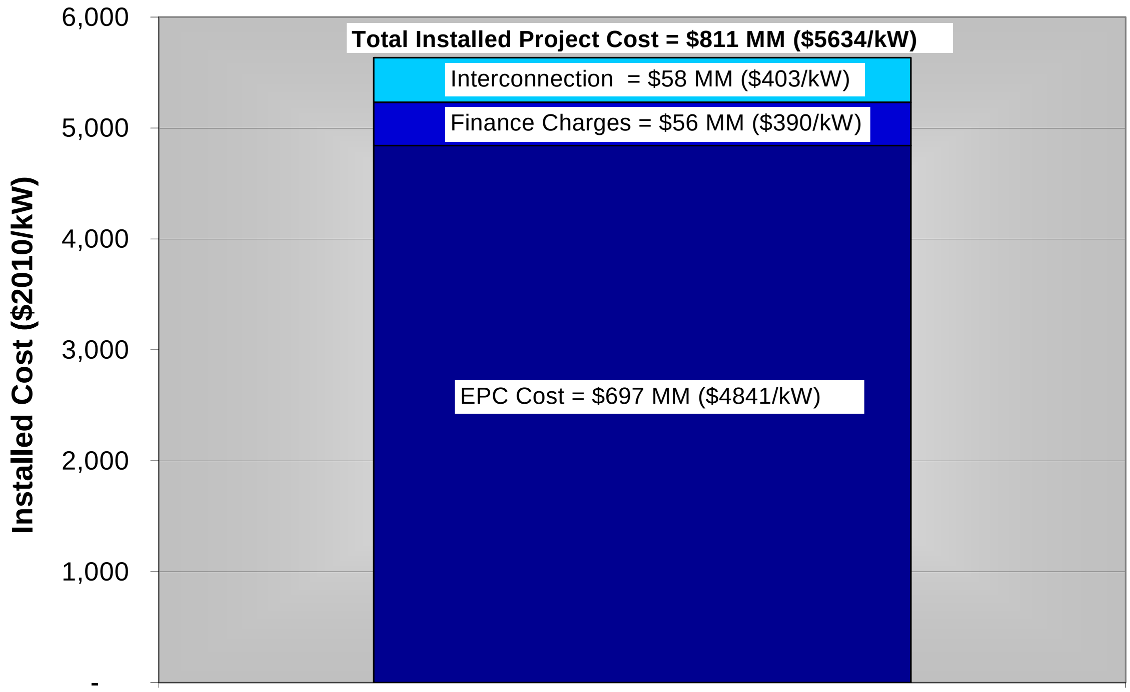
For purposes of this report, the cost of the Project in excess of each of the above benchmarks is referred to as the respective "Green Premium." We have generally expressed the Green Premium in terms of aggregate annual value as well as $ per MWh. Pace Global's scope did not call for any recommendations on the acceptability of the Green Premium, and we have made none.

TASK 1 SUMMARY

Pace Global reviewed the cost estimates provided by FPLE. The cost of the wind farm alone is $5,231 per kW, while LIPA's underwater cable and on-shore substation upgrade costs elevate the project's costs to $5,634 per kW. Exhibit 1 shows the components of the capital cost estimate in millions of dollars as well as dollars per kilowatt ("kW") of nameplate capacity.

[1] This Report and the information and statements herein are based in whole or in part on information obtained from various sources as of August 22, 2007.

Exhibit 1: Off-Shore Project Cost Estimate



Source: Pace Global

Engineering, Procurement, and Construction ("EPC") costs for off-shore wind projects have been rising steadily in recent years due to elevated metals prices and increased wind turbine demand versus supply. Generic estimates for European installations are expected to exceed $4,000 per kW before the inclusion of interconnection costs within a few years. Most of the difference between the FPLE estimate of $5,231 per kW (before interconnection) and the European $4,000-per-kW value appears to be traceable to known installation differences in North America, contingencies in construction costs associated with the Long Island project and an approximately $500 per kW premium on the North American GE turbine. The contingencies appear appropriate to the nature of the project, while it is difficult to attribute a precise cause to the turbine cost differential.

GE is the likely supplier of these off-shore wind turbines, but no turbine supplier is well mobilized to provide offshore turbines to the North American market. GE's only experience with this particular turbine has been in the Arklow Banks project off the shores of Ireland. The Arklow Banks project experienced some operational difficulties that appear to be reasonable for an embryonic application. So based on available information, it is not feasible to ascertain if the turbine-cost differential is attributable to an appropriate assessment of the risk of the new technology, or conversion of European technology to a North American application, or simply GE extracting higher profits from an illiquid marketplace. Yet it should be noted that given all suppliers' tepid interest in selling off-shore wind turbines in the undeveloped North American market, there is some risk that the current estimates may increase to more unfavorable levels over time. Therefore, on balance we believe the FPLE cost estimates are reasonable and we have used them in our analysis.

TASK 2 SUMMARY

Pace Global evaluated the economics of the proposed wind farm[2] against three benchmarks. We compared the present value costs of the Project to:

1. A 20-year forecast of wholesale power prices on Long Island, utilizing a generation dispatch simulation model incorporating Pace Global's database of existing generation and future expansions ("Zone K Power"),
2. The 20-year costs of an alternative combined cycle gas-fired turbine ("CCGT") consistent with LIPA's resource planning in the non-renewable domain, and
3. A representative on-shore wind farm that could conceivably be developed in the western PJM[3] market zone ("PJM Wind"), incorporating the assumption that the energy and capacity could then be delivered, via transmission across PJM, to LIPA's Neptune cable in eastern PJM.

   This hypothetical on-shore wind resource is believed to represent a renewable alternative with the highest probability of economic viability. However, it should be recognized that no specific development activities have been undertaken and the values used herein could change significantly upon the selection of a specific site and the conduct of a full due diligence.

For the Project versus each benchmark, the analysis compared the aggregate costs in present value terms as well as a levelized cost per MWh over a 20-year horizon. The levelized cost per MWh reflects a representative price differential over twenty years after consideration of the fact that near-term dollars are more valuable than future dollars.

For each of those comparisons, Pace Global made independent assessments of fuel prices, capacity values, emissions and carbon cost burdens, and numerous other assumptions that are documented in the following report. No attempt was made to value externalities beyond those assumptions. For example, the potential health benefits of wind generation versus fossil-fuel generation are only represented inasmuch as our emissions and carbon values are explicitly incorporated in the assumptions. The results of our analysis are presented in Exhibit 2 and Exhibit 2a below.

[2] Wind values were evaluated in the context of a broader generation portfolio of equal installed capacity value per rules of the NY-ISO.

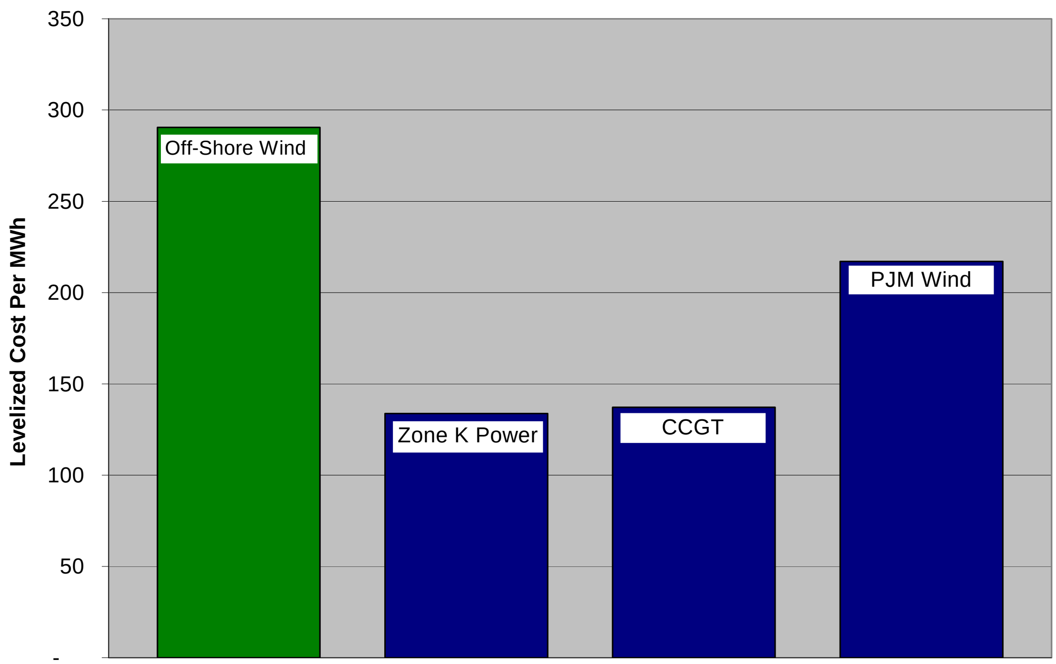
[3] PJM refers to the Pennsylvania, Jersey, Maryland power grid, operated by the PJM Independent System Operator (PJM ISO).

Exhibit 2: Summary of Project Cost Comparisons

	Levelized Cost* $/MWh	Green Premium of Project* $/MWh**	Levelized Green Premium* $ Million / Year
Off Shore Wind "The Project"	**291**		
Zone K Power	134	157	67
CCGT	137	153	66
PJM Wind[4]	215	76	32

*Values reflect levelized costs beginning in 2010.
** By way of reference, Green Premiums may be compared to $15/ MWh results of latest NYSERDA REC auction
Levelized Cost plus the Green Premium may not sum to the Off-Shore Wind Levelized Cost due to rounding.
Source: Pace Global

Exhibit 2a: Graphic of Levelized Cost Comparisons



*Values reflect levelized costs beginning in 2010.
Source: Pace Global

Pace Global also conducted sensitivity analysis against the CCGT benchmark[5] to arrive at the necessary break-even values for fuel prices (which drive CCGT and Zone K Power wholesale power values), capital cost reductions, and carbon credit values (under postulated CO_2

[4] This value and the related NPV reflect the foregone opportunity cost associated with utilizing the Neptune cable to import lower-cost PJM energy; that value was estimated at $20 MWh.
[5] The CCGT and Zone K benchmarks are similar; the sensitivities were done for the CCGT only.

legislation). We found that the Green Premium would be reduced to zero if any of the following conditions existed:

- Natural gas prices averaged 2.9 times projected levels over the 20-year horizon.
- Capital costs for the Project were somehow decreased to $3,033 per kW, about 54% of current projections.

No foreseeable carbon values produced a break even result; we tested values for CO_2 avoidance up to $100 per tonne. The following document provides further details as to the assumptions and methodologies used in the analysis that produced the above findings.

PROJECT BACKGROUND

The Project is a proposed 144 MW wind farm off the coast of Long Island, New York. LIPA issued a Request for Proposals ("RFP") in January 2003 seeking proposals from vendors to develop, own, operate, and maintain a 100-140 MW wind powered electric plant to be located within a specific target area off the south shore of Long Island.

LIPA received qualified proposals in response to the Offshore Wind RFP from two vendors. In June 2004, based upon the recommendation of the selection committee, LIPA's Board of Trustees approved the selection of FPLE and authorized the commencement of negotiations to secure a power purchase agreement and any other related agreements with FPLE regarding the Offshore Wind Park.

LIPA has been in negotiations with FPLE for several years, during which time the market for and price of offshore wind projects have changed dramatically. Under this proposal FPLE would develop the offshore wind project utilizing GE equipment, and then sell the output of that wind farm to LIPA. The Project calls for forty 3.6 MW units, constituting a total maximum generating capacity of 144 MW requiring approximately $697 million of capital expenditures before any interconnection cost and allowance for interest during construction.

ANALYSIS OF FPLE COST ESTIMATES

Pace Global reviewed the cost estimates for the Project provided by FPLE on a per-kW basis. Once interest during construction is included, the cost of the wind farm alone is estimated at $5,231 per kW, while LIPA's underwater cable and on-shore substation upgrade costs elevate the Project's costs to $5,634 per kW.

Although North America has seen tremendous growth in its land-based wind power developments, the off-shore market still poses additional development obstacles. These include the lack of incentives to invest in high-cost offshore technologically, specialized infrastructure needed to develop large-scale offshore facilities, and the uncertain regulatory environment in the U.S. regarding siting and other aspects of this type of technology. Wind project EPC costs have risen substantially in recent years due to elevated metal prices and increased demand for wind turbines. In addition, offshore wind farm costs are inherently greater than those for land-based developments because of difficulty of installation, additional foundation and support requirements, underwater cabling and interconnection requirements, and additional maintenance costs. Pace Global's analysis of the current status of the offshore wind market in Europe indicates that offshore development costs for generic projects are expected to reach a level of approximately $4,000/kW by 2010, inclusive of interest during construction but excluding contingencies and interconnection expenditures.

Although FPLE's estimate is higher than these observed prices in Europe, most of the difference appears to be traceable to known installation differences in North America, contingencies in construction costs associated with the Long Island project and an approximately $500 per kW premium on the North American GE turbine. The contingencies appear appropriate to the nature of the project, while it is difficult to attribute a precise cause to the turbine cost differential.

GE is the likely supplier of these off-shore wind turbines, but no turbine supplier is well mobilized to provide offshore turbines to the North American market. GE's only experience with this particular turbine has been in the Arklow Banks project off the shores of Ireland. The Arklow Banks project experienced some operational difficulties that appear to be reasonable for an embryonic application. So based on available information, it is not feasible to ascertain if the turbine-cost differential is attributable to an appropriate assessment of the risk of the new technology, or conversion of European technology to a North American application, or simply GE extracting higher profits from an illiquid marketplace.

It should be noted that given all suppliers' tepid interest in selling off-shore wind turbines in the undeveloped North American market, combined with the trend in turbine demand, and metals prices, there is some risk that the current estimates may increase to more unfavorable levels with time. These issues generally support the FPLE cost estimate, and on balance we believe the FPLE cost estimates are reasonable and we have used them in our analysis. (A copy of Pace Global's broader assessment of the domestic market is provided as a supplement to this Report.).

FINANCIAL ANALYSIS

Pace Global performed a financial analysis to evaluate the costs of the Project relative to:

1. Projected marginal power prices at the wholesale level in Long Island (NY-ISO Zone K),
2. A conventional gas-fired generation alternative, and
3. An alternative onshore wind farm.

In colloquial terms, the analysis answered three questions: how would the Project compare to the "normal" expectations for Long Island power; how would it compare to a particular conventional technology; and, on a preliminary screening, how might a lower-cost renewable project fair as an alternative.

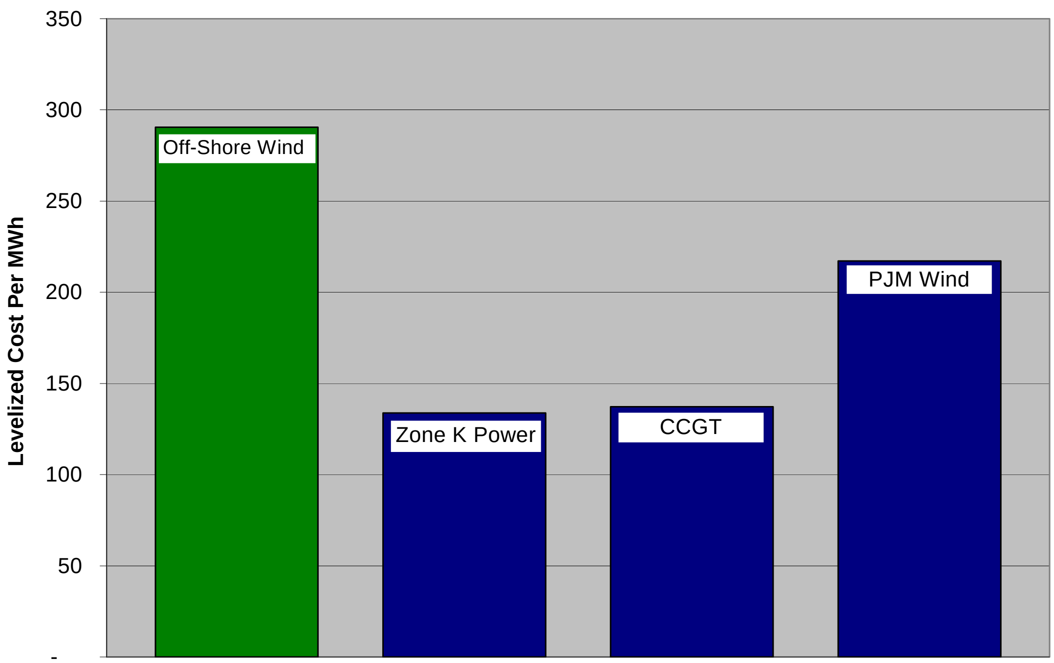
The answers to these questions are presented in tabular and graphical format below:

Exhibit 3: Summary of Project Cost Comparisons

	Levelized Cost* $/MWh	Green Premium of Project* $/MWh**	Levelized Green Premium* $ Million / Year
Off Shore Wind "The Project"	**291**		
Zone K Power	134	157	67
CCGT	137	153	66
PJM Wind[6]	215	76	32

*Values reflect levelized costs beginning in 2010.
** By way of reference, Green Premiums may be compared to $15/ MWh results of latest NYSERDA REC auction
Levelized Cost plus the Green Premium may not sum to the Off-Shore Wind Levelized Cost due to rounding.
Source: Pace Global

Exhibit 3a: Graphic of Levelized Cost Comparisons*



*Values reflect levelized costs beginning in 2010.
Source: Pace Global

[6] This value and the related NPV reflect the foregone opportunity cost associated with utilizing the Neptune cable to import lower-cost PJM energy; that value was estimated at $20 MWh.

METHODOLOGY AND SUMMARY FINDINGS

Pace Global conducted a 20-year financial analysis under which the above comparisons were made. Project costs were assumed to be covered by a long-term Power Purchase Agreement ("PPA"), whereby LIPA would pay FPLE for power generation and the price would be sufficient to recover projected capital and operating costs of the Project.

Cost of Service Calculations

The costs of generation from the Off-Shore Wind, the CCGT, and PJM Wind projects were estimated by determining the annual purchased power agreement price ("PPA") of generation in $/MWh that allowed the asset owners to fully recoup their costs over the life of each project. The PPA price modeling is based on several cost components:

- **Capital Recovery Costs:** The PPA is assumed to be offered by a private-sector developer, requiring both the return of and on capital expenditures through the application of standard debt-to-equity shares to the total installed project cost. Debt is financed on an assumed term at the assumed cost of debt starting in the first year of each project. Equity investment is required to earn a prescribed after-tax rate of return over the 20-year life of the project.
- **Fuel Costs:** The volumes of natural gas consumed by the CCGT technology are priced at Pace Global's standard forecast prices as of 2007:Q1. The CCGT unit will also emit CO2 during the course of operations which are included as a variable fuel cost (a description of Pace Global's CO2 price forecast can be found in Appendix A below).
- **Operating and Maintenance Costs:** The variable and fixed costs of operating and maintaining the units in service are estimated on a cost per MWh of gross generation or per kW of installed capacity, respectively.
- **Interconnection Costs:** The off-shore wind and CCGT projects require the installation and upgrade of facilities by LIPA to allow for interconnection of the projects to the grid. The capital cost is treated as debt and recovered over a 20-year term. Any annual operating expenditures are in addition to the capital recovery costs.

Calculating the Green Premium vs. Zone K

To perform the first comparison, the costs of the Project were compared to projected NY-ISO Zone K market prices[7] in order to determine the additional cost LIPA would incur over and above expected market values, assuming normal evolution of Zone K power markets. The benchmark for this first comparison, firm power prices at the wholesale level in Long Island, was Pace Global's routine quarterly forecast of power prices.[8]

[7] Inclusive of energy and capacity
[8] The forecast used corresponds to Pace Global's projections as of 2007:Q1.

Comparing the Project to Zone K Power price projections resulted in an aggregate Green Premium of $803 million. To put that premium in terms that ratepayers could relate to, we also calculated the Green Premium in levelized costs per MWh over the 20-year time horizon. That value is $157/MWh or 15.7 cents per KWh. The levelized cost per MWh reflects a representative price differential over twenty years giving recognition to the fact that near-term dollars are more valuable than future dollars.

Calculating the Green Premium vs. Conventional Gas-Fired Generation

The Green Premium per MWh was calculated as the total cost per MWh of wind power versus the total cost per MWh of the CCGT. Then to arrive at an annual dollar value we simply multiplied the Green Premium per MWh times the number of "green" MWh's produced by the Project. That annual stream of dollar values was reduced to a net present value ("NPV") in order to arrive at the NPV Green Premium. That NPV Green Premium was calculated to be $787 million. We also calculated the levelized Green Premium to be $153/MWh, or 15.3 cents per KWh, over the 20-year time horizon.

Alternative Onshore Wind Farm

Pace Global also performed an analysis comparing the costs of the Project with those of an onshore wind farm in a neighboring region in order to represent a reasonable economic assessment of a renewable alternative. Note that no specific development activities have been undertaken and the values used in this analysis could change significantly upon the selection of a specific site and the conduct of a full due diligence.

Large-scale options for renewable technology development are limited on Long Island, Pace Global performed a high-level examination of the economics of acquiring wind-generated power from Pennsylvania, where onshore wind resource development is viable. Pace Global developed the following assumptions for this hypothetical project:

- A generic estimate for on-shore wind project development, permitting, construction, and capital costs was developed for the PJM region. A total all-in cost of $2,924 per kW was estimated for the hypothetical project, including costs related to interconnection to the PJM power grid.
- Just as NY-ISO rules recognize effective offshore capacity at 38% of nameplate capacity, onshore capacity receives a 20% capacity recognition value. So the onshore wind farm was sized at 275 MW to maintain parity.
- Transmission costs were developed through an analysis of likely rates for the purchase of firm transmission through the PJM system and for the congestion rents that would be levied when moving power from the western part of PJM to the Neptune cable.
    - The PJM Network Service Integration rate indicates that transmission costs will be approximately $3 per MWh during the on-peak time period and $2 per MWh

during off-peak. Pace Global assumed $2.50 per MWh as the cost for the transmission.[9]

- An analysis of three years of historical peak power prices in western Pennsylvania and eastern New Jersey indicated that an average difference of $10.34 per MWh existed between these two zones. This value was assumed to represent the congestion charges that would be assessed.[10]

- Separately, Pace Global projected in recent studies that the long-term differential between PJM-East and Zone K would be approximately $20/MWh. That value was used to represent the foregone value of using the Neptune cable to transmit wind power rather than more economic energy from PJM into Zone K.
- Analysis of line losses through the system indicated that a 2.2% loss rate should be applied to move power through PJM, while a 2.7% loss factor accounts for transfer across the Neptune line. Therefore, a total, multiplicative loss factor of 4.84% was applied to the generation for this option in order to represent actual delivery of electricity to LIPA territory.
- Historical capacity factors for existing wind units in Pennsylvania were compared with generic average assumptions in order to arrive at the base assumption of a 30% annual capacity factor[11] for this hypothetical unit.

Using the above assumptions and those outlined in more detail below, Pace Global determined that the levelized cost of this option would be $215/ MWh and the NPV Green Premium would be $386 million, while the levelized Green Premium would be $76 / MWh or 7.6 cents per kWh.

SENSITIVITY ANALYSES

In order to examine break-even values for the Green Premium and the sensitivity of the Project's economics to input assumptions, several scenarios were evaluated using alternative fuel costs, different environmental compliance costs, and varying capital costs.

[9] This cost estimate assumes the capacity is fully utilized.

[10] A proposed Capacity Export Charge Tariff is now before the FERC but not yet approved. This additional charge could result in a lower Green Premium of the Project compared to the onshore alternative due to price separation between zones within PJM.

[11] The capacity factor is a measure of energy produced expressed as a percentage of the maximum output capability of the generator

Pace Global first tested the assumptions that would be required to drive the Green Premium to zero. The following conclusions were reached:

- Natural gas prices would need to rise to 2.9 times the current forecast values in each year of the study period in order for the levelized Green Premium to be eliminated. Whereas the current forecast for natural gas prices between 2010 and 2020 averages about $9 per MMBtu (nominal $), prices would have to average over $25 per MMBtu over the same time period in order for the Green Premium to fall to zero.
- No reasonable CO_2 allowance price (i.e., below $100 per tonne CO_2) would equilibrate the two options.
- An all-in installed cost of approximately $3,033 per kW (including the cost of the substation and interconnection by LIPA) for the wind resource would drive the premium to zero, versus the value of $5,634 assumed in the Base Case. Such a cost assumption is nearly half the current estimate.
- The Green Premium decreases from $153 per MWh to $138 per MWh when a total all-in capital cost of $2,071 per kW is applied to the CCGT representing an illustrative high capital cost estimate for CCGT capacity installed on Long Island.

Other Scenarios – Fuel and Carbon Costs

In order to further test sensitivity to fuel price assumptions, Pace Global imposed its low and high gas price assumptions[12] for Henry Hub natural gas prices. A third scenario representing an aggressive carbon dioxide policy was also simulated. The cost of these options is summarized in Exhibit 4.

Exhibit 4: Summary of Gas Price and Carbon Sensitivity Scenario Results

	Green Premium* $/MWh	Levelized Annual Green Premium** $Million Per Year
Base Case	153	
High Gas Prices	139	60
Low Gas Prices	182	78
Aggressive Carbon	128	55

*Values reflect levelized costs beginning in 2010 relative to the CCGT alternative.
**Levelized Annual Green Premium represents the levelized annual cost as of 2010 based on the generation from the off-shore wind project times the $/MWh Green Premium in each year relative to the CCGT alternative.
Source: Pace Global

Since gas prices are the largest single component of the marginal costs incurred in operating a gas-fired generating unit, changes in the fuel price forecast can have a significant impact on the economic profile of that unit relative to other resources. Wind units consume no fuel at all, while the variable costs of the CCGT unit, and the NY-ISO market as a whole, are largely

[12] High and low values were assessed to reflect 25-percent and 75-percent confidence that future values would not exceed the respective gas price levels.

defined at the margin by gas prices. Therefore, the net difference in total cost to LIPA under the High Gas Price Case scenario is approximately $73 million less than in the Base Case, resulting in a levelized Green Premium of $139 per MWh.

As in the case of high gas prices, we saw a significant impact on the comparative economics of the resource options when we imposed low gas prices. The net difference in total cost to LIPA is approximately $150 million higher than in the Base Case, resulting in a $182 per MWh Green Premium.

Pace Global also explored a scenario that would represent an aggressive carbon dioxide policy aimed at the electric sector. Future carbon policy is highly speculative, but proposed policies that call for emissions reductions within the next decade without the ability to procure offsets outside of the country indicate that carbon compliance costs of $35 per tonne CO_2 are plausible (in real 2006$). Such a scenario would also likely lead to increased demand and increased prices for natural gas. Therefore, Pace Global performed a sensitivity analysis where the natural gas price was at the 75% confidence band[13], and the CO_2 cost was assumed to be $47.04 per tonne starting in 2015 and escalating at the rate of inflation thereafter. In this case, the difference in levelized costs between the wind option and the combined cycle option was calculated to be $128 per MWh, indicating that such a scenario will still fall well short of equilibrating the options on a levelized cost basis.

FURTHER DETAILED RESULTS

The annual cost differentials underlying the levelized comparisons of the Green Premium associated with the Project are presented in Exhibit 5 and Exhibit 6 relative to each alternative technology discussed in previous sections. Exhibit 7 graphs the annual Green Premium for each alternative and Exhibit 8 provides detail supporting the estimates.

[13] A confidence band refers to a probability assessment for uncertain values. In this case a 75% confidence band would indicate that we are 75% confident that future values would not exceed that level of gas price.

Exhibit 5: Comparison of Annual Off-Shore Wind Green Premium by Alternative

Variable	Units	NPV or Annuity Price	2010	2011	2015	2020	2025	2029
Off-Shore Wind vs. Zone K Energy Value Alternative								
Green Premium Per MWh Generated	**$/MWh**	**$156.79**	**128.17**	**139.43**	**151.78**	**161.23**	**169.91**	**186.99**
Annual Cost of Green Premium	**$MM**	**$803**	**37**	**61**	**67**	**71**	**74**	**82**
Zone K Total Energy Value PerMWh	$/MWh	133.80	107.86	97.01	112.94	143.89	182.05	207.75
Off-Shore Wind vs. Combined Cycle Alternative								
Green Premium Per MWh Generated	**$/MWh**	**$153.34**	**113.73**	**129.97**	**146.15**	**160.28**	**174.80**	**200.57**
Annual Cost of Green Premium	**$MM**	**$787**	**33**	**57**	**64**	**70**	**77**	**88**
CCGT Energy Cost Per MWh	$/MWh	137.25	122.31	106.47	118.57	144.84	177.15	194.17
Off-Shore Wind vs. PJM Wind Alternative								
Green Premium Per MWh Generated	**$/MWh**	**$75.52**	**67.39**	**62.73**	**69.22**	**78.48**	**89.21**	**99.02**
Annual Cost of Green Premium	**$MM**	**$386**	**20**	**27**	**30**	**34**	**39**	**43**
PJM Wind Energy Cost Per MWh	$/MWh	215.06	168.64	173.70	195.51	226.64	262.74	295.72
Off-Shore Wind Reference Values								
Energyy Cost Per MWh	**$/MWh**	**290.59**	**236.04**	**236.44**	**264.72**	**305.12**	**351.95**	**394.74**
Annual Generation	**MWh**		**292,195**	**438,292**	**438,292**	**438,292**	**438,292**	**438,292**

Assumptions

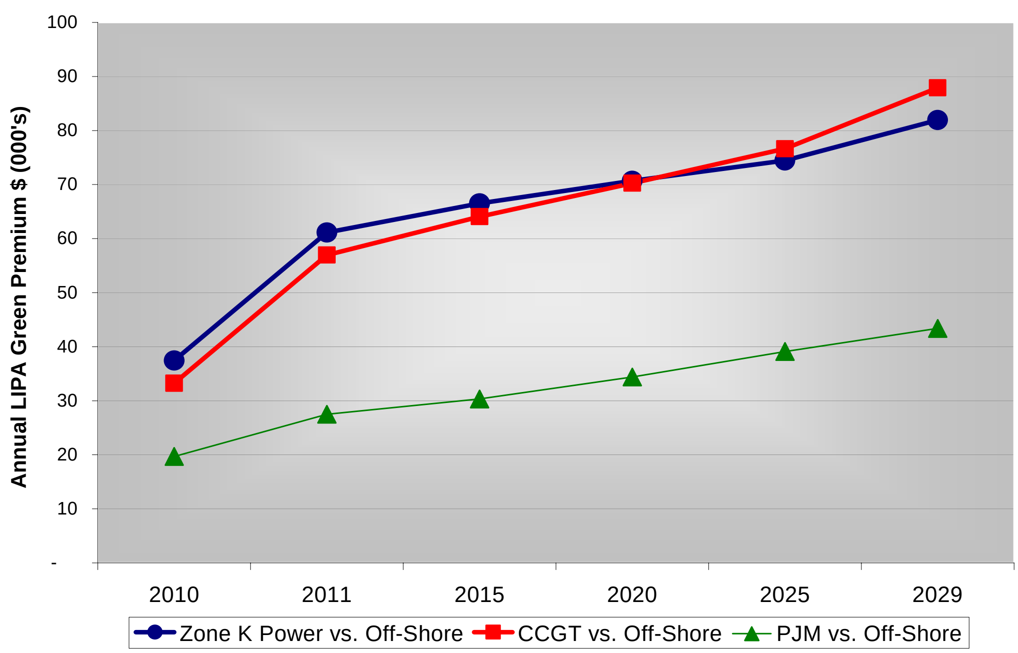
Discount Rate	Percent	5.50%
Annuity Period	Years	20

Notes

2010 costs are lower due to partial-year operation.

Source: Pace Global.

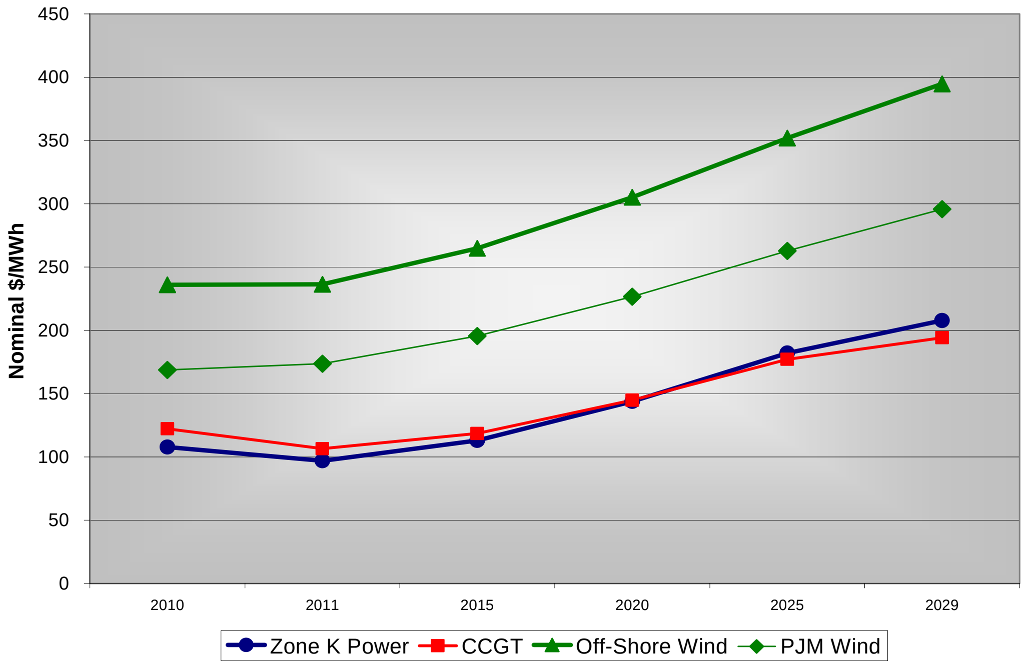
Exhibit 6: Annual Off-Shore Wind Green Premium Value by Alternative



2010 costs lower due to partial-year operation.

Source: Pace Global

Exhibit 7: Summary of Cost per MWh by Alternative



Source: Pace Global

Exhibit 8: Detailed Green Premium Inputs by Alternative

Variable	Units	NPV or Annuity Price	2010	2011	2015	2020	2025	2029
Combined Cycle Gas Turbine								
CCGT Cost Per MWh Delivered	**$/MWh**	**137.25**	**122.31**	**106.47**	**118.57**	**144.84**	**177.15**	**194.17**
Annual Cost	**$000**	**247,458**	**150,562**	**196,590**	**218,938**	**267,441**	**327,107**	**358,528**
Capital Recovery	$000		35,884	53,827	53,827	53,827	53,827	53,827
Fuel (Including Carbon Credits)	$000		84,814	106,151	124,300	166,805	219,519	244,588
Annual Operating Expense	$000		26,709	33,457	37,657	43,654	50,607	56,959
Interconnection Cost	$000		3,155	3,155	3,155	3,155	3,155	3,155
Annual Energy Delivered to LIPA	**MWh**		**1,230,988**	**1,846,482**	**1,846,482**	**1,846,482**	**1,846,482**	**1,846,482**
Capacity (ICAP Basis)	MW		300	300	300	300	300	300
Effective Capacity Factor	Percent		70%	70%	70%	70%	70%	70%
Off-Shore Wind								
Off-Shore Wind Cost Per MWh Delivered	**$/MWh**	**290.59**	**236.04**	**236.44**	**264.72**	**305.12**	**351.95**	**394.74**
Annual Cost	**$000**	**124,626**	**68,969**	**103,628**	**116,025**	**133,732**	**154,259**	**173,011**
Capital Recovery	$000		49,934	77,148	86,830	100,660	116,693	131,339
Annual Operating Expense	$000		13,631	21,061	23,704	27,479	31,856	35,854
Interconnection Cost	$000		5,403	5,420	5,491	5,593	5,710	5,818
Annual Energy Delivered to LIPA	**MWh**		**292,195**	**438,292**	**438,292**	**438,292**	**438,292**	**438,292**
Capacity (ICAP Basis)	MW		55	55	55	55	55	55
Nameplate Capacity	MW		144	144	144	144	144	144
NY-ISO Capacity Contribution	Percent		38%	38%	38%	38%	38%	38%
Effective Capacity Factor	Percent		35%	35%	35%	35%	35%	35%
PJM Wind								
PJM Wind Cost Per MWh Delivered	**$/MWh**	**215.06**	**168.64**	**173.70**	**195.51**	**226.64**	**262.74**	**295.72**
Annual Cost	**$000**	**142,664**	**76,160**	**117,667**	**132,435**	**153,529**	**177,982**	**200,321**
Capital Recovery	$000		53,968	75,354	84,811	98,319	113,979	128,284
Annual Operating Expense	$000		22,192	42,314	47,624	55,210	64,003	72,036
Annual Energy Delivered to LIPA	**MWh**		**451,601**	**677,401**	**677,401**	**677,401**	**677,401**	**677,401**
Capacity (ICAP Basis)	MW		55	55	55	55	55	55
Nameplate Capacity	MW		275	275	275	275	275	275
NY-ISO Capacity Contribution	Percent		20%	20%	20%	20%	20%	20%
Effective Capacity Factor	Percent		28%	28%	28%	28%	28%	28%

Assumptions

Discount Rate	Percent	5.50%
Annuity Period	Years	20

Notes

2010 costs lower due to partial-year operation.
Capacity is net of degradation.
Capacity factor is a measure of energy produced expressed as a percentage of the maximum output capability of the generator.
Effective Capacity Factor is net of unit outages and line losses to delivery point into LIPA service territory.

Source: Pace Global

APPENDIX A: ASSUMPTIONS

The following section outlines the major assumptions that were utilized to develop the results shown above. Pace Global utilized fuel cost estimates that were independently developed and our proprietary forecast of NY-ISO Zone K market prices.

OFF-SHORE WIND FARM ASSUMPTIONS

The basic assumptions related to the wind farm operating parameters are taken from the original wind project evaluation model developed in 2003. The primary changes include a re-assessment of the capacity factor of the units based on a review of more recent wind velocities and power curve data, as well as the revised in-service date of May, 2010. In addition to the operating parameters, various financing, installed capital cost, and operating cost assumptions were taken from the original wind power assessment model and supplemented with information based on the latest cost estimate from FPLE. LIPA is independently responsible for the underwater cable and on-shore substation upgrade, estimated at approximately $58 million (including IDC). The assumptions used in the assessment of the off-shore Project are presented in Exhibit 9.

COMBINED CYCLE UNIT ASSUMPTIONS

LIPA's combined cycle gas turbine ("CCGT") cost assumptions were used in the Base Case analysis, although a sensitivity test was conducted using Pace Global's independent estimate of potentially much higher installed capital costs. The assumptions used in the assessment of the CCGT based on LIPA's installed cost estimates are presented in Exhibit 10.

PJM WIND FARM ASSUMPTIONS

The assumptions outlined below in Exhibit 11 were used to analyze the hypothetical on-shore renewable development in Pennsylvania.

Exhibit 9: Summary of Off-Shore Wind Farm Operating, Financial, and Cost Assumptions

Technical Assumptions		
Total Installed Capacity	MW	144
Commercial Operation Date ("COD")	MMM-YYYY	May-2010
Capacity Credit for ICAP	Percent	38.00%
Effective Capacity Factor (Net of Losses)	Percent	34.75%
Average Annual Capacity Factor	Percent	36.00%
Annual Outage Rate	Percent	3.00%
Losses to Point of Delivery	Percent	0.50%
Annual Degradation Factor	Percent	NA
Financing and Valuation Assumptions		
Method of Depreciation	Type	5-Year MACRS
Effective Marginal Income Tax Rate	Percent	35.00%
Weighted-Average Cost of Capital ("WACC")	Percent	9.52%
Debt Share of Capitalized Expenditures	Percent	55%
Term of Debt	Years	13
Cost of Debt	Percent	9.00%
Cost of Equity	Percent	14.00%
Project Analysis Period	Years	20
Production Tax Credit ("PTC")	$2007/MWh	19.00
Duration of Production Tax Credit from COD	Years	10
Installed Capital Cost Assumptions (Nominal Dollars)		
Total Installed Capital Cost	$000	753,289
Total Installed Capital Cost Per Unit	$/kW	5,231
Project Cost	$000	697,071
Interest During Construction	$000	56,218
Start Date for Development	MMM-YYYY	May-2008
Start Date for Construction	MMM-YYYY	Nov-2008
Interest Rate During Construction	$000	10%
Operating and Maintenance Costs (Constant 2010 Dollars)		
Total Annual Operating Costs	$000	20,447
Total Annual Operating Costs Per Unit	$/MWh	45.03
Fixed Operating and Maintenance ("FOM") Costs	$000	13,631
FOM	$/kW-Year	94.66
Annual Capital Expenditures	$000	6,816
Portion of Capital Expenditures Expensed	Percent	35.00%
Depreciation Life of Annual Capital Expenditures	Years	5
Interconnection Upgrade and Underwater Cable Costs		
Total Costs of Interconnection with IDC	$000	58,000
Total Costs of Interconnection with IDC Per Unit	$/kW	403
Cost of Debt For Interconnection	Percent	5.50%
Term of LIPA Bond	Years	20
Operating and Maintenance Costs	$/kW-M	0.32

Exhibit 10: Summary of CCGT Operating, Financial, and Cost Assumptions

`	Units	Value
Technical Assumptions		
Total Installed Capacity	MW	306
Annual Degradation Factor	Percent	2.00%
Adjusted ICAP Capacity	MW	300
Commercial Operation Date ("COD")	MMM-YYYY	May-2010
Heat Rate	MMBtu/MWh	7.25
Effective Capacity Factor (Net of Losses)	Percent	70.3%
Average Annual Capacity Factor	Percent	71.0%
Losses to Point of Delivery	Percent	1.00%
Financing and Valuation Assumptions		
Method of Depreciation	Type	20-Year MACRS
Effective Marginal Income Tax Rate	Percent	35.00%
Weighted-Average Cost of Capital ("WACC")	Percent	7.89%
Debt Share of Capitalized Expenditures	Percent	75%
Term of Debt	Years	15
Cost of Debt	Percent	9.00%
Cost of Equity	Percent	14.00%
Project Analysis Period	Years	20
Installed Capital Cost Assumptions (Nominal Dollars)		
Total Installed Capital Cost	**$000**	**413,954**
Total Installed Capital Cost Per Unit	$/kW	1,353
Installed Capital Cost	$000	376,120
Interest During Construction ("IDC")	$000	37,834
Construction Begin Date	MMM-YYYY	May-2008
Interest Rate During Construction	Percent	10.00%
Operating and Maintenance Costs (Constant 2010 Dollars)		
Total Annual Operating Costs	$000	32,483
Total Annual Operating Costs Per Unit	$/MWh	17.42
Fixed Operating and Maintenance ("FOM") Costs	$000	6,558
FOM	$/kW-Year	21.43
Variable Operating and Maintenance ("VOM") Costs	$000	5,595
VOM	$/MWh	3.00
Estimated Annual Generation (Before Losses)	GWh	1,865
Other Annual Operating Costs from COD Year	$000	20,330
PILOTs Pass-Through	$000	7,288
Upstream Gas System Costs	$000	13,042
One-Time Fees Payable at COD	$000	6,297
Community Benefits	$000	6,297
Interconnection Upgrade Costs		
Total Costs of Interconnection with IDC	$000	37,700
Total Costs of Interconnection with IDC Per Unit	$/kW	123
Cable and Interconnection Costs	$000	37,700
Cost per Unit	$/kW	123
Interconnection Capacity	MW	306
Cost of Debt For Interconnection	Percent	5.50%
Term of LIPA Bond	Years	20

Exhibit 11: Summary of PJM Wind Farm Operating, Financial, and Cost Assumptions

Variable	Units	Value
Technical Assumptions		
Total Installed Capacity	MW	275
Commercial Operation Date ("COD")	MMM-YYYY	May-2010
Capacity Credit for ICAP	Percent	20.00%
Effective Capacity Factor (Net of Losses)	Percent	28.12%
Average Annual Capacity Factor	Percent	30.00%
Annual Outage Rate	Percent	1.50%
Losses to Point of Delivery	Percent	4.84%
Annual Degradation Factor	Percent	NA
Financing and Valuation Assumptions		
Method of Depreciation	Type	5-Year MACRS
Effective Marginal Income Tax Rate	Percent	35.00%
Weighted-Average Cost of Capital ("WACC")	Percent	9.52%
Debt Share of Capitalized Expenditures	Percent	55%
Term of Debt	Years	13
Cost of Debt	Percent	9.00%
Cost of Equity	Percent	14.00%
Project Analysis Period	Years	20
Production Tax Credit ("PTC")	$2007/MWh	19.00
Duration of Production Tax Credit from COD	Years	10
Installed Capital Cost Assumptions (Nominal Dollars)		
Total Installed Capital Cost	**$000**	**804,008**
Total Installed Capital Cost Per Unit	$/kW	2,924
Project Cost	$000	744,425
Interest During Construction	$000	59,583
Start Date for Development	MMM-YYYY	May-2008
Start Date for Construction	MMM-YYYY	Nov-2008
Interest Rate During Construction	$000	10%
Operating and Maintenance Costs (Constant 2010 Dollars)		
Total Annual Operating Costs	$000	41,081
Total Annual Operating Costs Per Unit	$/MWh	57.71
Fixed Operating and Maintenance ("FOM") Costs	$000	14,030
FOM	$/kW-Year	51.02
Transmission and Congestion Cost	$000	23,377
Transmission and Congestion Charges	$/MWh	32.84
Estimated Annual GWh Entering PJM	GWh	712
Annual Capital Expenditures	$000	3,673
Portion of Capital Expenditures Expensed	Percent	35.00%
Depreciation Life of Annual Capital Expenditures	Years	5

ADDITIONAL ASSUMPTIONS OF INTEREST

The wind farm is highly variable in terms of power generation, both seasonally as well as daily. This issue required additional analysis to determine if an average annual price of power could be reasonably applied to total annual wind farm generation. Also, as noted above, the CCGT fuel costs include the cost of carbon dioxide emissions that are based on Pace Global's forecast of allowance prices. The outcome of the hourly wind generation assessment and the rationale behind the carbon dioxide allowance price forecast, as well as its application in the analysis, are provided in subsequent sections.

Hourly Price and Generation Analysis

Pace Global performed its financial analysis on an average annual basis only after verifying that average annual cost and generation assumptions are appropriate to use for this particular intermittent wind resource.

Due to the intermittent nature of wind resources, it was necessary to analyze both monthly and hourly variations in expected generation because expected power prices vary considerably across months and over the course of a day. Pace Global examined hourly wind speeds offshore of Zone K for a representative year and estimated expected generation under such conditions. In addition, an hourly power price forecast was completed for the year 2008.

Using these hourly generation and price projections, Pace Global calculated expected hourly revenues for the wind resource and compared them to a hypothetical resource that runs every hour at the annual average wind capacity factor. It was found that projected revenues in both scenarios were nearly identical, less than ½ of 1% difference. Therefore, no adjustment was made to the annual cost model to account for wind variation.

Treatment of CO_2

Assumptions regarding the future cost of carbon dioxide ("CO_2") emissions are important in this assessment because they will affect the price of power and costs faced by fossil fuel generators that will not burden wind generators. Therefore, Pace Global explicitly forecasted CO_2 compliance costs for inclusion in its power market forecast and in its cost estimates for fossil fuel-fired generation.

Although there are no current or pending U.S. regulations for CO_2 emissions, international and national support for control of these emissions continues to grow. At the moment, the political support for a CO_2 control program is greater in some states than at the national level. The Regional Greenhouse Gas Initiative ("RGGI"), a cap-and-trade program covering power plant CO_2 emissions, is being launched in the Northeast, with New York as a member. Although the first compliance period begins in 2009, reductions below the cap are not required until after 2014. Therefore, Pace Global believes low-cost mitigation efforts, including offsets, will be prevalent through 2014. A more substantial compliance cost is forecast for generators starting in

2015. Exhibit 12 displays Pace Global's carbon compliance cost assumptions in nominal dollars through 2026. These assumptions are based on RGGI modeling and analysis of federal policy proposals. Although RGGI includes certain price mitigation features, it is uncertain if offset options will cap the compliance costs in the future or if stricter federal policy will supersede state actions. The current forecast considers this uncertainty.

Pace Global's CO_2 compliance cost forecast results in an increase in expected power prices for Zone K, because all generator types that emit CO_2 will face increased variable costs. As a simple example, a compliance cost of $10 per tonne would be expected to raise the variable costs of an efficient gas-fired combined cycle unit about $4 per MWh and raise the variable costs of a coal unit around $9 per MWh. In terms of modeling, additional costs, shown in Exhibit 12, were added to the combined cycle unit to reflect its increased variable costs of operating. For the non-emitting wind unit, no cost or revenue parameters were altered, as the CO_2 benefit was embedded in the power price forecast.

Exhibit 12: CO_2 Compliance Costs to Generators in RGGI States (nominal $)

Year	$/tonne CO_2	$/MWh*
2015	3.80	1.49
2016	3.96	1.55
2017	4.18	1.63
2018	4.67	1.83
2019	5.14	2.01
2020	12.46	4.87
2021	12.83	5.02
2022	13.22	5.17
2023	13.61	5.33
2024	17.38	6.80
2025	26.23	10.26
2026	27.01	10.57

*The $/MWh calculation assumes a 7,250 Btu/kWh heat rate for a gas-fired combined cycle unit.

Source: Pace Global

MARKET POWER PRICE ASSUMPTIONS

Exhibit 13: NY Zone K Market Price Results – Base Case (nominal $)

Year	Energy Off-Peak ($/MWh)	Energy Peak ($/MWh)	Energy Average ($/MWh)	Average ICAP ($/kW-yr)	All-In Off-Peak ($/MWh)	All-In Peak ($/MWh)	All-In Average ($/MWh)	Gas Price for NYC ($/MMBtu)
2010	78.59	114.23	95.56	107.24	78.59	139.94	107.80	9.21
2011	66.67	101.98	83.48	117.97	66.67	130.26	96.95	7.69
2012	67.68	104.00	84.98	113.88	67.68	131.31	97.98	7.78
2013	70.24	109.18	88.78	108.53	70.24	135.20	101.17	8.03
2014	73.58	115.04	93.32	108.90	73.58	141.15	105.75	8.36
2015	79.34	123.72	100.47	108.65	79.34	149.77	112.87	8.80
2016	83.43	127.30	104.32	111.71	83.43	154.08	117.07	9.23
2017	88.17	134.73	110.34	102.50	88.17	159.30	122.04	9.75
2018	93.34	141.64	116.34	95.75	93.34	164.60	127.27	10.31
2019	98.71	149.91	123.09	94.41	98.71	172.55	133.87	10.88
2020	107.06	161.66	133.06	94.15	107.06	184.23	143.80	11.42
2021	112.39	169.62	139.64	92.57	112.39	191.81	150.21	12.06
2022	118.34	178.45	146.96	94.21	118.34	201.03	157.72	12.74
2023	124.96	188.37	155.15	90.30	124.96	210.02	165.46	13.45
2024	129.93	195.53	161.17	92.00	129.93	217.58	171.67	13.99
2025	138.65	207.78	171.57	90.89	138.65	229.57	181.94	14.51
2026	142.56	214.40	176.77	92.63	142.56	236.60	187.34	14.97
2027	148.93	224.56	184.94	94.31	148.93	247.17	195.71	15.68

Source: Pace Global 2007Q1 Outlook Service

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