August 17, 2011

VIA EDGAR SUBMISSION AND COURIER

Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549-3561
Attention: James Allegretto

Re: Exelon Corporation
Registration Statement on Form S-4
Filed June 27, 2011
File No. 333-175162
Form 10-K for Fiscal Year Ended December 31, 2010
Filed February 10, 2011
Form 8-K
Filed April 27, 2011
File No. 001-16169

Ladies and Gentlemen:

We are writing in response to the comments contained in the Staff's comment letter dated July 25, 2011 (the "2011 Comment Letter") with respect to Exelon Corporation's ("Exelon") Registration Statement on Form S-4, as filed with the Securities and Exchange Commission ("Commission") on June 27, 2011 ("Form S-4"), Form 10-K for Fiscal Year Ended December 31, 2010, as filed with the Commission on February 10, 2011 ("2010 Form 10-K"), and Form 8-K, as filed with the Commission on April 27, 2011 ("Form 8-K").

For the convenience of the Staff's review, we have set forth the comments contained in the Staff's Comment Letter along with Exelon's responses. All responses to this letter are provided on a supplemental basis.

* * * *

Form S-4 Registration Statement Filed June 27, 2011

Unaudited Pro Forma Condensed Combined Consolidated Financial Statements, page 162

Note 5. Pro Forma Adjustments to Financial Statements, page 171

1. **Please tell us your basis in GAAP for recognizing a regulatory asset offset for the adjustment to reflect Constellation's third-party debt at estimated fair value. Please include a detailed discussion of facts and circumstances supporting your conclusion including a discussion of whether and how each regulatory jurisdiction incorporate interest or other debt-related costs in base rates. Please explain whether any of BGE's regulatory jurisdictions utilize a hypothetical debt structure and what effect you believe it will or should have on your recording of a regulatory offset relating to debt. We may have further comment.**

Response:

Regulated utilities generally recover their long-term debt costs through a cost-of-capital component incorporated into the rates the utility charges its customers for its services. Specifically, a utility is granted by its rate regulatory commission an allowed rate of return that is applied to the amounts the utility has prudently invested in the property, plant and equipment used to distribute electricity or gas to its customers. This aggregate investment amount is generally referred to as the utility's rate base.

A utility's revenue requirement is the total amount of revenues determined by the regulator that the utility is allowed to recover from across its customer base. A utility's allowed revenue requirement is generally comprised of (1) a component for recovery of the day-to-day operating and maintenance costs necessary to maintain the utility's routine operations and (2) a component for a reasonable return on the capital invested by the utility to serve its customers (i.e., a return on the rate base).

The rate of return allowed by the rate regulatory commission generally is designed to provide a fair return to debt and equity investors, and is usually based on a utility's actual capital structure. That is, the allowed rate of return reflects a weighted average cost of capital based on a utility's proportionate debt and equity capitalization structure and specific allowed return rates for both debt and equity. Allowed debt returns are generally based on the actual cost of the utility's actual outstanding debt. The allowed rate of return may be reset annually or as part of the general rate cycle, depending on the jurisdiction and individual utility.

Under this rate making approach, the utility's interest expense is a direct input in the ratemaking process and the utility generally recovers the actual costs of its debt (i.e., actual interest costs based on its outstanding debt's stated interest rates). Fluctuations in the fair value of such debt instruments, then, generally do not impact the amount of debt costs recovered by the utility. Because there is a mechanism to estimate allowable costs as discussed in ASC 980-10-05-3 (and further discussed in the Basis for Conclusions section of FAS 71, paragraph 57), we believe it is appropriate to offset the purchase accounting adjustments to reflect debt at fair value with the establishment of corresponding regulatory assets or regulatory liabilities. Such accounting best reflects the true economics associated with the utility's debt costs whereby interest expense recognized matches the actual interest being incurred and recovered by the utility. Specifically, in periods subsequent to the application of purchase accounting, the amortization of the regulatory asset or regulatory liability will offset the amortization of the purchase accounting adjustment to reflect debt at fair value, thereby resulting in recognition of interest expense at the actual amounts being incurred and recovered by the utility under the regulatory rate construct.

In certain jurisdictions, the determination of a utility's authorized rate of return may assume a theoretical (or hypothetical) capital structure—that is, a prescribed proportionate split between debt and equity rather than the utility's actual debt to equity capital structure percentages. Usually the hypothetical capital structure is not significantly different from the utility's actual capital structure; and in such cases, we believe it continues to be appropriate to apply the regulatory accounting described. However, situations where the hypothetical capital structure is materially different from a utility's actual capital structure would require careful assessment as to whether the criteria set forth in ASC 980 are still appropriately met.

In the case of Baltimore Gas and Electric Company (BGE), the Maryland Public Service Commission (PSC) and the Federal Energy Regulatory Commission (FERC) have allowed the utility to recover its debt costs based on its actual capital structure. For example, in its most recent March 2011 rate order, the PSC established the allowed rate of return based on BGE's actual capital structure as of the last day of its rate case test year (i.e., June 30, 2010). Another example comes from the FERC method for determining BGE's transmission rates. Through its formula rate approach, FERC utilizes the actual capital structure and the actual cost of debt to establish an allowed rate of return on BGE's transmission rate base. As such, we believe the establishment of a regulatory asset offset to the purchase accounting adjustment made to reflect BGE's debt at fair value is appropriate.

2. **Please tell us your basis in GAAP for recognizing Constellation's regulatory assets and liabilities, particularly those not earning a return, at carrying value as opposed to their acquisition-date fair value.**

Response:
Based on our initial review as well as on preliminary discussions with Constellation's management, we believe there will be no significant acquisition-date fair value adjustments required for the majority of Constellation's regulatory assets and liabilities as they are earning a return or accruing interest at reasonable rates, respectively. However, we plan to adjust the carrying value to fair value for Constellation regulatory assets that are not in BGE's rate base and therefore not earning a return.

The regulatory assets not earning a return are a result of the deregulation of electric generation in Maryland when BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business and the related tax impacts. As a result, BGE wrote-off its individual, generation-related regulatory assets and liabilities. BGE established generation-related regulatory assets, a portion of which are in rate base and a portion of which are not in rate base, to be collected through its regulated rates, which are being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The book value of the regulatory assets was approximately $80 million at June 30, 2011 and will be amortized through 2017. Although not significant to Exelon, we will include a fair value adjustment for these assets in the pro forma financial statements included in Amendment No. 1 to the Form S-4.

3. **We note a number of blank spaces. Please complete the information by filling in the blanks prior to effectiveness.**

Response:
We have included in Amendment No. 1 to the Form S-4 all omitted information other than dates and related information that are not yet determinable, such as (i) date, time and place of the special meeting, (ii) the record date for the special meeting, (iii) the mailing date of the proxy statement/prospectus and (iv) certain information to be provided as of the record date or the last practicable date before the date of the proxy statement/prospectus.

<u>Form 10-K for Fiscal Year Ended December 31, 2010</u>

<u>Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, page 63</u>

<u>Critical Accounting Policies and Estimates, page 75</u>

<u>Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation), page 76</u>

4. Please tell us the escalation percentages you used to estimate future decommissioning costs for the past three years and whether you use blended escalation factors or separate escalation factors for labor, equipment and other materials, energy, LLRW disposal and other costs. Please also tell us the indices upon which the escalation factors are based, if indices were used. In short, please show us why your inflation assumptions related to future decommissioning costs are supportable with historical experience and similar assumptions used by other licensees.

Response:
We use four separate escalation factors applied to the five major cost categories to estimate future decommissioning costs. The five major cost categories and the four indices from the U.S. Bureau of Labor Statistics used to determine the escalation rates are as follows:

- Labor – Employment Compensation Index, Compensation All Private Industry Workers
- Equipment and materials – Producer Price Index, Machinery & Equipment
- Energy – Producer Price Index, Fuels & Related Products & Power
- Burial – Consumer Price Index, Services
- Other – Consumer Price Index, Services

The following table represents the long-term (30-year) escalation rates used to estimate future decommissioning costs for the past three years:

Long-Term Escalation Rates	**Q3 2010 Update**	**Q3 2009 Update**	**Q3 2008 Update**
Labor	2.95%	3.11%	3.38%
Equipment and Materials	0.47%	0.53%	0.30%
Energy	5.58%	4.43%	6.46%
Burial & Other	2.78%	3.02%	3.18%

Given the rates are intended to reflect long-term cost escalation patterns, and given escalation rate forecasts have fluctuated significantly from year-to-year, we utilize a model in which both actual historical and forecasted future escalation rates are considered in deriving the escalation rates used in our future decommissioning costs as follows:

- 70% weighting based on the most recent 15 years of actual historical escalation experience
- 10% weighting based on the forecasted escalation rates from two years prior
- 10% weighting based on the forecasted escalation rates from one year prior
- 10% weighting based on current year forecasted escalation rates

A 70% weighting is applied to actual historical escalation rates as we believe actual changes in the various cost factors over a long duration (i.e., 15 years) are the most relevant and objectively determinable indicators for estimating future costs. The 30% weighting applied to forecasted escalation rates is derived by equally blending the latest three years of forecasted escalation rates to take into account the short-term volatility in such forecasts relative to the long-term nature of the decommissioning costs estimates being determined.

We obtain the forecasted escalation rates annually from IHS Global Insights, a third-party expert in the area of price and cost analysis. Although we have not formally benchmarked the methodology used to calculate the escalation factors with other nuclear operators, we understand that other large nuclear operators use similar indices.

Item 8. Financial Statements and Supplementary Data, page 150

Combined Notes to Consolidated Financial Statements, page 178

12. Asset Retirement Obligations (Exelon, Generation, ComEd and PECO), page 260

<u>Nuclear Decommissioning Trust Fund Investments, page 262</u>

<u>NRC Minimum Funding Requirements, page 264</u>

5. **We note that you determine the ARO using multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations. Please tell us your consideration of disclosing:**

   - **The degree to which any of the multiple scenario based cost estimates are lower than the Nuclear Regulatory Commission's minimum formula amount, and if so, the reasons why such estimates are lower than the NRC formula amount.**

   - **The model you use and a sensitivity analysis of changes in assumptions.**

Response:
As discussed in our response to your comments contained in the Staff's letter dated August 25, 2010 ("2010 Comment Letter") with respect to Exelon's Form 10-K for the fiscal year ended December 31, 2009, as filed with the Commission on February 5, 2010, the underlying decommissioning liability considered in the NRC minimum funding calculation is inherently different from the corresponding decommissioning liability reflected in the GAAP ARO.

The NRC minimum funding and GAAP ARO determinations differ primarily given disparate assumptions regarding (1) the alternative decommissioning approaches to be used and (2) the likelihood of operating the nuclear units through an anticipated license renewal period; as well as the requirement under ASC 410-20 to escalate and discount the estimated decommissioning costs to a present value in the determination of the GAAP ARO. In response to your 2010 Comment Letter, we included incremental disclosures in Note 12, Asset Retirement Obligations (page 264), in the 2010 Form 10-K to inform the reader of the differences between the NRC minimum funding calculation and the measurement of the GAAP ARO under ASC 410-20.

In addition to the factors disclosed in the 2010 Form 10-K, there are also differences between the NRC minimum funding and GAAP ARO determinations in (1) how decommissioning costs are estimated and (2) the types of decommissioning costs included in the determinations.

Cost estimation methodology – For each unit, the NRC allows a nuclear licensee the option of determining the required minimum funding amount through either a formulaic rate or a site-specific cost estimate. The generic NRC formulaic rate is applied as the first method to determine adequate funding assurance. If adequate funding assurance is not demonstrated using the formulaic rate, the regulations allow for a site-specific cost estimate to be utilized to determine whether Generation is adequately funded under the NRC regulations for that particular unit. The NRC formulaic rate approach is based on generic, non-site specific decommissioning cost studies performed for the NRC in the early 1980's with specified static cost estimates (adjusted for inflation) based on the reactor type (PWR or BWR) and power level of the reactor.

In its most recent minimum funding filing with the NRC, Generation applied the formulaic rate for twelve of its nineteen operating units and derived a site-specific cost estimate for the other seven units. In contrast, the GAAP ARO is determined for each unit on a site-specific cost estimate basis (and not a generic formulaic rate approach).

The site-specific determinations are based on cost estimates developed by TLG Services, a third-party expert in the area of decommissioning and cost estimation for the nuclear and radioactive material industry. These cost estimates are updated for each unit at least once every five years.

Costs included in the calculations – Only the costs necessary to decommission radiologically contaminated equipment, structures and land are considered in determining the NRC minimum funding requirement. In contrast, the cost estimates included in the calculation of the GAAP ARO include all legally unavoidable costs to decommission the unit (as required under ASC 420-10). Accordingly, in addition to the removal of radiologically contaminated equipment, structures and land, the GAAP ARO cost estimates also include: (1) the costs to fully restore the nuclear site to a “greenfield” position for certain of our nuclear units based on the regulatory framework of the state in which the units operate; (2) costs to dispose of low-level radioactive waste during the operation of the unit; and (3) costs to manage and store spent nuclear fuel on site subsequent to ceasing operations, either in the spent fuel pool or dry cask storage, until the DOE accepts the spent fuel for permanent storage.

Given the inherent differences between the determinations, we do not believe specific disclosure of the degree to which any of the multiple scenario based GAAP ARO cost estimates are lower than the NRC’s minimum formula amount would be relevant or material to the financial statement users.

We do believe, as evidenced by our disclosures (included below) in the 2010 Form 10-K as set forth in the notes to the financial statements on page 264 and referenced in the Liquidity and Capital Resources section on page 133, that a description of the differences in assumptions, inputs and methodologies between the two determinations is appropriate and useful. Further, in the 2011 Form 10-K, we will supplement our existing disclosures with the following highlighted changes to further describe the differences in the cost estimation methods and the costs included in the calculations, as described above.

NRC Minimum Funding Requirements. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation’s and Exelon’s Consolidated Balance Sheets primarily due to differences in the types of costs included in the estimates, the bases for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key criteria and assumptions used in the minimum funding calculation under the NRC methodology at December 31, 2011 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the assumption plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2011 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the assumption plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions, except Oyster Creek with an assumed end-of-operations date of 2019); (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 6.2% through a period of approximately 30 years after the end of the extended lives of the units; and (5) an estimated targeted annual after-tax return on the NDT funds of 4.6% to 5.4% (as compared to a historical 5-year annual average after-tax return of approximately 5%).

As we have in the past, as further described in our response to Comment No. 6 below, we also believe it is appropriate to disclose any specific instances in which a unit's NDT fund balance is less than the NRC minimum funding requirement, including a description of the approach taken by Exelon or Generation (such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts) to ensure NRC minimum funding requirements are met.

Decommissioning Model and Sensitivity Analysis:

In response to the Staff's 2010 Comment Letter, we increased the sensitivity disclosures included in the Critical Accounting Policies and Estimates on pages 76-77 of the 2010 Form 10-K which we believe provides adequate information for the reader to understand the impact that changes in key assumptions could have on the calculation of the ARO. Additionally, the critical accounting policy disclosures include information on all of the significant assumptions used in the determination of the ARO, including decommissioning cost studies being performed on a rotational basis every five years and cost escalation studies utilizing inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs.

Accounting Implications of the Regulatory Agreements with ComEd and PECO, page 265

6. **We note your disclosure that the NDT funds of each of the former ComEd units exceeded the related decommissioning obligation for each of the units, and for the purposes of making this determination, the decommissioning obligation referred to is the ARO reflected on Generation's Consolidated Balance Sheet at December 31, 2010 and is different from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines. Please tell us your consideration of disclosing: (i) whether NDT funds for each of the units is greater than or less than the NRC minimum funding obligation; and (ii) if NDT funds for any of the units is less than the NRC minimum funding obligation and the reasons for the difference.**

Response:
As disclosed in Note 12, Asset Retirement Obligations, of the 2010 Form 10-K (page 264), NRC regulations require that the licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facilities at the end of their lives. As explained further in our response to Comment No. 5 above, the NRC's minimum funding determination is based on specific criteria and assumptions prescribed by the NRC to project an estimated decommissioning obligation and a projected NDT fund investment amount.

The specific criteria and assumptions used under the NRC methodology to project an estimated decommissioning obligation are inherently different from methodologies used to measure the decommissioning liability reflected in the GAAP ARO.

Likewise, the determination of the projected NDT fund investment amount under the NRC methodology is not directly comparable to the actual amount of NDT fund investments as of any particular date. For example, the NRC methodology measures a projected NDT fund investment amount assuming actual current fund balances will grow at a 2% (3% for the former PECO units, as specified by the Pennsylvania Public Utility Commission) annual after-tax return rate through a unit's current license expiration date. As the NRC allows for growth in the trust fund investments through the expected license termination date (an average of 25 years across the nuclear generation fleet) in the determination of compliance with the minimum funding requirements, disclosing NDT trust assets (which are carried at fair value on Generation's consolidated balance sheet) that are less than the NRC minimum funding requirement could lead a reader of the financial statements to believe Generation is in non-compliance with the NRC's requirements when in fact, at December 31, 2010, Generation was in compliance at each of its units.

As such, disclosure of how the existing NDT fund investment balances as of a specific balance sheet date compare to the corresponding NRC determination would not be meaningful or useful for readers of the financial statements.

We do believe, however, that it is useful and appropriate to disclose any specific instances in which a unit is in non-compliance with the NRC minimum funding requirement, as well as a description of the approach taken by Exelon and/or Generation under NRC guidelines (such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts) to ensure the NRC minimum funding requirements are met.

For example, in Note 12 to the 2010 Form 10-K on page 267, we disclosed that the Byron and Braidwood units were underfunded as of December 31, 2009, under the NRC minimum funding requirement calculation. We disclosed that Exelon had remediated this position with the establishment of approximately $175 million in parent guarantees (initially $44 million). We also disclosed that as of December 31, 2010, given modest recovery in the financial markets, Generation determined the level of Byron and Braidwood NDT fund investments both met NRC minimum funding requirements.

Further, we disclosed in the notes to the financial statements and in Item 1A, Market and Financial Risks (pages 32 and 33) that future market conditions may impact Generations minimum funding status, the risk that Exelon and/or Generation might be required to take steps to ensure NRC minimum funding requirements are met for each of its units, and that such steps could significantly adversely affect Exelon's and/or Generation's cash flows and financial position. The disclosure noted that such steps could include providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts.

We believe, in total, our current disclosures are sufficient to inform the reader of the risk associated with meeting the NRC's minimum funding requirements and of any instances in which such minimum requirements have not been met during the periods covered by the financial statements.

18. Commitments and Contingencies (Exelon, ComEd and PECO), page 291

Environmental Issues, page 300

Section 316(b) of the Clean Water Act, page 301

7. **We note that you revised the economic useful life of Oyster Creek used in determining depreciation and the asset retirement obligation to reflect your decision to retire Oyster Creek by December 31, 2019 and the execution of the Administrative Consent Order with the New Jersey Department of Environmental Protection. Based on the expiration date of the current operating license, it appears that the Nuclear Regulatory Commission previously approved an extension of the initial 40-year operating license for Oyster Creek. If our assumption is incorrect please advise in detail. If our assumption is correct, please tell us (i) when the operating license was extended (ii) whether you revised the useful life of Oyster Creek used in determining depreciation and the asset retirement obligation and (iii) when and how you revised the useful life and the facts and circumstances you considered, including your consideration of the impact of New Jersey state-level permit programs. If you did not anticipate the early retirement of Oyster Creek, please discuss the events and circumstances between the date the Nuclear Regulatory Commission approved the extension of the operating license and/or the date you revised the useful life of Oyster Creek and the decision to cease generating operations by December 31, 2019.**

Response:
The Staff's assumption regarding the NRC's extension of the Oyster Creek operating license is correct. Our response to your comments is as follows:

(i) Oyster Creek received its operating license extension from the NRC in April 2009.

(ii) In 2001 (the year Exelon Generation Company was formed), Generation updated its useful life assumption on all of its majority-owned nuclear units to reflect management's best estimate that each of the units would be operated through an anticipated renewal period (up to 60 years in total). Consistent with prior years, the license renewal assumption is disclosed in Note 1, Significant Accounting Policies, of the 2010 Form 10-K (page 190). Upon Generation's December 2003 acquisition of the remaining 50% interest in AmerGen (former owner of the Oyster Creek, Three Mile Island (TMI), and Clinton nuclear stations), Generation also changed the useful life estimates related to the depreciation of Oyster Creek, TMI, and Clinton. Accordingly, at that time it was management's best estimate that Oyster Creek would receive a 20-year license extension through 2029 and extended the estimated service life of Oyster Creek by 20 years. Likewise, in establishing the ARO for each of Exelon's nuclear generating units (including Oyster Creek), Generation assumed a successful 20-year license renewal. As a result, the receipt of Oyster Creek's license renewal in April 2009 had no effect at that time on the amount of Oyster Creek's depreciation expense or the determination of its ARO because Generation had already assumed for purposes of establishing the ARO that it would receive the license renewal.

(iii) The useful life of Oyster Creek was adjusted from 2029 to 2019 in December 2010. Between December 2003 and December 2010, Generation continually monitored regulatory and economic developments associated with Oyster Creek as a basis for reaffirming each period the appropriateness of its assumed remaining useful life.

The following provides a timeline with respect to various Federal and state rulings and economic factors that were considered when evaluating Oyster Creek's useful life. In particular, Generation has closely monitored the implications on Oyster Creek of the changing requirements of Section 316(b) of the Clean Water Act. Most of this information was disclosed in Note 18, *Commitments and Contingencies* in the Form 10-Ks and Form 10-Qs filed from December 31, 2004, through March 31, 2011:

- In July 2004, the U.S. EPA issued the final Phase II rule implementing Section 316(b) of the Clean Water Act. The Clean Water Act requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. The Phase II rule provided each facility with a number of compliance options and permitted site-specific variances based on a cost-benefit analysis. The requirements were intended to be implemented through state-level National Pollutant Discharge Elimination System (NPDES) permit programs.

- In a draft permit issued in July 2005, as part of the pending NPDES permit renewal process for Oyster Creek, the New Jersey Department of Environmental Protection (NJDEP) preliminarily determined, in its best professional judgment, that closed-cycle cooling and environmental restoration were the only viable options for Section 316(b) compliance at Oyster Creek. The NJDEP advised Generation that it would issue a new draft permit, and reiterated its preference for cooling towers as the best technology available for closed-cycle cooling.

- In January 2007, the U.S. Second Circuit Court of Appeals remanded the Phase II rule back to the U.S. EPA for revisions. The court found that with respect to a number of significant provisions of the rule, the EPA exceeded its authority under the Clean Water Act, failed to adequately set forth its rationale for the rule, or failed to follow required procedures for public notice and comment. By its action, the court invalidated certain compliance measure options that had been supported by the utility industry because they were cost effective and provided existing plants with needed flexibility in selecting the compliance option appropriate to a specific plant's location and operations. On July 9, 2007, the EPA formally suspended the Phase II rule.

- In April 2009, the U.S. Supreme Court reversed the decision of the U.S. Second Circuit Court of Appeals in one respect, and determined that the EPA could use a cost-benefit analysis under Section 316(b) to determine the best technology available for minimizing adverse environmental impact at cooling water intake structures. The U.S. EPA began reconsidering the rule on remand, expecting to ultimately take further action consistent with the opinions of the Supreme Court and the Court of Appeals, including whether to exercise its discretion to retain or modify the cost-benefit rule as it appeared in the initial Phase II rule.

- On January 7, 2010, the NJDEP issued its draft NPDES permit for Oyster Creek that would have required, in the exercise of its best professional judgment, the installation of cooling towers as the best technology available within seven years after the effective date of the permit. Oyster Creek was required to operate under its current permit, issued in 1994, until the draft permit was finalized after a period of public comment. At that time, Generation believed the public comment period and regulatory process could take up to two years before a final permit was issued.

- In November 2010, the US EPA reached a settlement with the plaintiffs in the Section 316(b) litigation that required the US EPA to issue a proposed rule by March 14, 2011 (see below), and to publish the final rule by July 27, 2012. Until then, the state permitting agencies continue their current practice of applying their best professional judgment to address impingement and entrainment requirements at plant cooling water intake structures.

- Given the uncertainties about the specific nature, scope and timing of any final US EPA compliance requirements and their impact on specific state regulations, Generation was in on-going discussions with the NJDEP from 2005 through 2010 to identify less costly alternatives to the installation of cooling towers.

- Concurrent with changes in the EPA compliance requirements, Generation was also monitoring long-term power market projections at this time to determine whether it was economically feasible to install cooling towers, if required. Long-term power projections reflected steady increases from 2005 through 2008, but then dropped significantly during 2009 and 2010 reflecting the decrease in the forecasted price of natural gas. Up through 2008, installing cooling towers was economically feasible; however, beginning in 2009, the overall economic viability of installing cooling towers at Oyster Creek began to decline. In fact, in 2010, it became more apparent that the value of Oyster Creek was higher if shut down in 2019 than if cooling towers were installed and the plant was run through 2029.

- Negotiations with the NJDEP continued into the fourth quarter of 2010 when, given the NJDEP's insistence that closed cycle cooling towers be installed, and considered together with the aforementioned declines in long-term power market price projections, on December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. In reliance upon Exelon's determination to cease generation operations no later than December 31, 2019, the NJDEP determined that closed cycle cooling is not the best technology available for Oyster Creek given the length of time that would be required to retrofit from the existing once-through cooling system to a closed-cycle cooling system and given the limited life span of the plant after any installation of such a closed-cycle cooling system. Based on its consideration of these and other factors, in its best professional judgment, NJDEP determined that the existing measures at the plant represent the best technology available for the facility's cooling water intake system. Generation and the NJDEP executed the associated Administrative Consent Order on December 8, 2010.

- On March 28, 2011, the EPA issued the proposed regulation. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment mortality, including application of a cost – benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The rule also imposes limits on impingement mortality, which likely will be accomplished by the installation of screens or similar technology at the intake. Exelon has determined that its decision to cease generation operations at Oyster Creek in 2019 remains prudent even after the EPA issuance of its proposed rule, as the state could have continued to enforce cooling towers as their determination of best technology available.

As illustrated above, there has been significant uncertainty for many years regarding the requirements of Section 316(b) of the Clean Water Act. Under the US EPA's Phase II rule provisions for compliance options and for site-specific, cost-benefit-analysis based variances, Generation had anticipated the ability to implement more economical compliance alternatives at Oyster Creek than the closed cycle cooling towers approach. Until the fourth quarter of 2010, Generation anticipated an ultimately favorable resolution of the compliance matter with the NJDEP through legal action or otherwise, such that the overall economics of the Oyster Creek unit would continue to justify operations through the extended license life of 2029.

At the same time, given the uncertainties associated with the compliance negotiations, Generation disclosed the following information in Note 18, Commitments and Contingencies, of the 2009 Form 10-K (and with similar disclosures in the 2010 quarterly Form 10-Qs) as follows:

> Generation estimates that the cost to retrofit Oyster Creek with closed cycle cooling towers would be approximately $700 million to $800 million. This cost estimate includes construction materials and labor, lost capacity and energy revenue during construction, and other ongoing incremental operating and maintenance costs. Generation believes that these additional costs would call into question the economic viability of operating Oyster Creek until the expiration of its current operating license in 2029, and Generation would close Oyster Creek if either the final Section 316(b) regulations or NJDEP requirements have performance standards that require the installation of cooling towers.

Litigation and Regulatory Matters, page 306

8. **We note your disclosure regarding asbestos personal injury claims and the savings plan claim and regarding various other litigation matters, and in particular your disclosure that the ultimate outcome of such matters is uncertain and may have a material impact on your results of operations, cash flows or financial position. Please tell us your consideration of disclosing an estimate of the reasonably possible loss or range of loss for each matter, or in the aggregate, or providing a statement that such estimates cannot be made in accordance with ASC 450-20-50-4. In addition, for those matters where you are unable to estimate the possible loss or range of loss, please tell us the procedures you undertake on a quarterly basis to attempt to develop a range of reasonably possible loss.**

Response:
We evaluate our loss contingencies at least quarterly to determine whether it is probable that a liability has been incurred (or an asset impaired) and whether the amount of loss is reasonably estimable. If these criteria are met, we record an accounting accrual (as required by ASC 450-20-25-2). We have determined that asbestos personal injury claims meet these criteria (as the liability was incurred when the asbestos exposure occurred during constructing and maintaining power plants and we have a reasonable basis for estimating losses from prior cases and other available information). We have accrued our best estimate of potential loss, both for existing claims and for an estimate of future claims, with the assistance of third-party valuation experts. We believe this is a reasonable estimate and do not expect any material adjustments in the future. As disclosed in our Form 10-K, there were no material adjustments during 2008, 2009 or 2010.

In cases where we have determined that the criteria for recognizing an accrual have not been met, but there is at least a reasonable possibility that a loss, or an additional loss above the amount accrued, may have been incurred we disclose the nature of the loss contingency and an estimate of loss or range of loss, or note that such an estimate cannot be made (as required by paragraphs 450-20-50-3 and 4).

The Savings Plan Claim was evaluated by management (including Exelon's internal legal department) and it was determined that it is not probable that a liability has been incurred. As a result, no accrual has been recorded. Based on managements evaluation of this case (which represents a dismissed claim which has been appealed and remains pending in appeals court, as disclosed in our 2010 Form 10-K), while it is reasonably possible that a loss will occur, there is not sufficient information available to allow management to develop a reasonable loss estimate or range of loss estimate. As a result, management disclosed the nature of the claim and stated that the outcome of the case is uncertain. In future filings, assuming no changes in facts, Exelon will include a statement that any potential loss associated with the case is not estimable.

In the *General* section under *Litigation and Regulatory Matters* in Note 18, *Commitments and Contingencies,* on pages 310 and 311 of the 2010 Form 10-K, Exelon describes its process of maintaining accruals for costs that are probable of being incurred and are reasonably estimable. Items of significance are disclosed separately (such as the asbestos personal injury claims and the Savings Plan claim). In future filings, as explained below, Exelon will expand its disclosure of its methods for evaluating general litigation and regulatory matters as follows:

General. The Registrants are involved in various other individually immaterial litigation matters in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for ~~costs~~ losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Exelon's legal counsel maintains records of outstanding matters that are updated and reviewed at least quarterly by internal legal counsel and, in many cases, external legal counsel, to evaluate whether any updates of accruals or estimates of loss (or range of loss) are appropriate. The legal department's evaluation includes discussions with the accounting and reporting functions to discuss outstanding matters for which accruals have not been recorded to determine whether those items meet the criteria for disclosure (i.e., it at least a reasonable possibility that a loss has been incurred), whether an estimate of loss can be determined for disclosure and materiality considerations.

Form 8-K Filed April 27, 2011

9. **We note that you present a full income statement in your reconciliations of adjusted (non-GAAP) operating earnings to GAAP consolidated statement of operations. Presenting a full non-GAAP income statement may attach undue prominence to the non-GAAP information. As such, please revise your reconciliations in future filings to simply reconcile net income to adjusted (non-GAAP) operating earnings. Please refer to Question 102.10 of our Compliance and Disclosure Interpretations: Non-GAAP Financial Measures.**

Response:
We have considered the Staff's interpretive guidance in Question 102.10 of Compliance and Disclosure Interpretations: Non-GAAP Financial Measures in connection with the information included in our quarterly Earnings Release and Earnings Release Attachment package (which is filed by Exelon quarterly as an exhibit to a Form 8-K). Respectfully, we do not believe the presentation in the Earnings Release Attachment of a full income statement reconciliation of adjusted (non-GAAP) operating earnings to GAAP net income attaches undue prominence to the non-GAAP information. As you suggest, we provide a simple reconciliation of net income to adjusted (non-GAAP) operating earnings prominently on page 2 of the actual Earnings Release document itself. Further, within the 14-page Earnings Release Attachment document, the full income statement reconciliation is not presented until page 6, after presentation of the complete GAAP income statements, balance sheets and cash flow statements. In addition, the Earnings Release Attachment is also accompanied by 42 presentation slides for the earnings release conference

call. Finally, the level of detail presented in the full income statement reconciliation provides transparency to our disclosures by providing useful information addressing questions we routinely receive from our securities analysts and investors, who seek detailed information as to specific line items to which reconciling adjustments are recorded to assist them in modeling their views of Exelon's future financial performance. By providing this information in the Earnings Release Attachment, we are able to make such information equally and consistently available to all investors and analysts, consistent with the requirements of Regulation FD.

* * * *

Exelon acknowledges that:

- should the Commission or the staff, acting pursuant to delegated authority, declare the filing effective, it does not foreclose the Commission from taking any action with respect to the filing;

- the action of the Commission or the staff, acting pursuant to delegated authority, in declaring the filing effective, does not relieve the company from its full responsibility for the adequacy and accuracy of the disclosure in the filing; and

- the company may not assert staff comments and the declaration of effectiveness as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

If you have any questions regarding the foregoing, please contact me at (312) 394-4736.

Very truly yours,

/s/ Duane M. DesParte
Duane M. DesParte
Vice President and Corporate Controller
Exelon Corporation