

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
BEFORE PRESIDENT JOSEPH L. FIORDALISO

I/M/O THE IMPLEMENTATION OF L. 2018,)
C.16 REGARDING THE APPROVAL)
ESTABLISHMENT OF A ZERO EMISSION) BPU DOCKET No. EO18080899
CERTIFICATE PROGRAM FOR TARIFF)
ELIGIBLE NUCLEAR POWER PLANTS)
)

COMMENTS ON BEHALF OF THE
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INTRODUCTION

Applicants PSEG Nuclear LLC (“PSEG”) and Exelon Generation Company LLC (“Exelon”) have failed to meet their burden to show that subsidies should be awarded for their nuclear power plants, Salem I, Salem II and Hope Creek. The statute establishing the criteria for the Board to consider in deciding whether “Zero Emissions Credits” (“ZECs”) are warranted requires the Applicants to demonstrate that their financial situation is such that without ZEC subsidies they will be forced to close the plants within the next three years and that if they do so, specific significant environmental harms will result. In making their case for ZEC subsidies, however, PSEG and Exelon have overstated their costs and understated their revenues. When their assumptions are examined more closely, their claims of financial hardship fall away. Moreover, the Applicants failed to demonstrate that closure of the units will have a significant and negative impact on New Jersey’s ability to comply with State air emissions reduction requirements. In the end, the information provided in the applications is not sufficient to demonstrate that the statutory criteria have been met or that the extraordinary relief of asking ratepayers to provide additional revenues to deregulated generation facilities should be awarded. The Companies’ request for subsidies should therefore be denied.

On the cost side, a substantial percentage of the “shortfall” claimed by the Applicants is attributed to their quantification of operational and market “risks” that they claim they will face if these plants continue to operate. With regard to operational risk, however, their “quantification” is based not on specific calculations of anticipated costs or events, but on formulaic additions to the units’ actual costs. In doing so, the Applicants only account for the negative, without any consideration that these risks could end up being positive, lowering the costs of the units rather than adding to their costs. With respect to the market risks, the

Applicants' estimates assume that the subsidies should protect them from nearly all of the risks associated with their participation in wholesale markets. In addition to the inappropriateness of asking ratepayers to assume the risk for these deregulated entities, the Applicants' calculations assume that ratepayers would get 0% of the upside. In other words, any positive outcomes in the markets would go to the Applicants while any negative outcomes would get charged to ratepayers.

The Applicants' estimates of costs also assume that any capital expenditures made by these plants should be accounted for in the same year they are incurred. This is inconsistent with basic accounting principles and would create significant intergenerational inequities. It also significantly mitigates the very risks that the Applicants claim they will face if they invest further in these plants without a guarantee of future profits sufficient to cover those expenditures. In addition, many of the future costs the Applicants claim they will face are ill-defined and may not be needed at all. Others, like Spent Fuel costs, are not actually being incurred by the Applicants. The costs of Support Services and Overhead are inflated, and hedging revenues and tax benefits from recent tax changes are not accounted for.

While the Applications inflate the units' future costs, they undervalue future revenues. The Applicants have selected a [BEGIN PSEG CONFIDENTIAL] [REDACTED] [END PSEG CONFIDENTIAL] on which to base their energy price projections even though an analysis of longer price trends would show that their revenues are likely to be much higher. They have not modeled the interactive effects on price if one unit shuts down, rather than all three simultaneously. They have also failed to take into account several initiatives at both the state and federal level that are likely to result in increases to energy and capacity prices. In short, they skewed the analysis of future revenues in order to deflate those revenues and support their claim

of financial distress. However, when more realistic revenue assumptions are made, and combined with a more accurate analysis of their likely costs, it becomes clear that they have failed to meet their burden of showing that the financial condition of these plants will force them to close.

The Applicants' environmental assumptions are also unrealistic. They assume that if these plants close they will be replaced in their entirety by gas plants, ignoring the state's offshore wind, solar and energy efficiency initiatives. They fail to take into account that the electricity from these plants is sold not only to load in New Jersey, but to customers in Delaware, Maryland, Pennsylvania and New York. They also fail to take into account that these plants are committed to providing electricity to the PJM markets for the next three years. Overall, the Applicants' assumptions on the environmental side are also formulaic and fail to reflect likely realities going forward.

As the Board of Public Utilities ("BPU" or "Board") is aware, Rate Counsel has always maintained that asking ratepayers to provide additional out-of-market subsidies to deregulated generating plants is inconsistent with the Electric Discount and Energy Competition Act ("EDECA"), with the orderly operation of federal wholesale markets, and with basic principles of ratemaking. It is also unfair given that ratepayers have already paid \$2.9 billion in "stranded" costs for these plants, and that the substantial profits made by these plants until recently were not shared with ratepayers but were paid instead to PSEG and Exelon shareholders. In a classic example of "heads I win, tails you lose," ratepayers are being asked to absorb all of the risks these plants may face in the future without gaining credit for any of the profits they made in the past or will make going forward.

Now, with the Applicants' providing the best case they could make, we can see that these subsidies are not only unfair and inappropriate, they are also unneeded. The only way the Applicants could justify their request is to over-count their costs and under-count their revenues. Throughout the legislative hearings on this bill the public was told that the BPU would be permitted to do a thorough and fair review and that if the Applicants did not meet their burden of proof, no subsidies would be awarded. In this submission, Rate Counsel is providing these comments as well as two expert certifications demonstrating the deficiencies in the applications. The Applicants have not met their burden of proof under the statute and as a result, their application for ZEC subsidies should be denied.

BACKGROUND

A. Utility Restructuring and Stranded Costs

Until the late 1990's, electric public utilities were regulated by the Board of Public Utilities under rate base rate of return, cost-of-service regulation, in which utilities were permitted to recover prudently-incurred costs and a return on capital investment. Customers purchasing electricity in New Jersey were served by the electric public utilities, investor-owned, vertically-integrated monopolies that provided generation, transmission, distribution and billing/collections services. On February 9, 1999, the New Jersey Legislature passed the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et. seq. ("EDECA"), which mandated the restructuring of the electric and natural gas industries in the State. Specifically with respect to the electric industry, EDECA allowed competition for electric generation industry in the hopes of reducing electric rates paid by ratepayers and improving the quality of choices for service. EDECA states that the intent of restructuring is to lower the current high cost of energy for all of the State's energy consumers and to place a greater reliance on competitive markets to meet the goal of lower prices. N.J.S.A. 48:3-50(a), N.J.S.A. 48:3-50 (b).

With the goal of lowering prices through competition, EDECA mandated that the Board implement, among other things, a statewide restructuring of the State's four electric public utilities. Pursuant to EDECA, investor-owned electric utility companies divested most of their generation fleet, but continued to transmit and deliver power to customers. The divestiture of generation plants created apparent stranded costs because the value of some plants on a utility's books was higher than what the electric utility received when divesting its asset. Unlike the other electric utilities in the State who divested their generation assets to unaffiliated entities, PSE&G divested its generation fleet, including PSE&G's ownership share of Salem 1 and 2 and

Hope Creek nuclear plants to its affiliate, PSEG Power. In re Public Service Elec. And Gas Company's Rate Unbundling, Stranded Costs and Restructuring Filings, 330 N.J. Super. 65 (App. Div. 2000). Because PSE&G's generation plants were not sold in the open market, the plants' valuation was administratively determined by the Board. In re Public Serv. Elec. & Gas Company's Rate Unbundling, 167 N.J. 377 (2001). EDECA also permitted stranded costs to be recovered from ratepayers and PSE&G was ultimately permitted by the Board to recover approximately \$2.9 billion in stranded costs. I/M/O Public Service Electric and Gas Company's Rate Unbundling, Stranded Costs and Restructuring Filings, BPU Docket Nos. EO97070461, EO97070462, EO97070463, Final Decision and Order, (August 24, 1999) ("PSE&G Unbundling Order") p. 104.

The terms and conditions of the divestiture were based on a non-unanimous Stipulation that was approved by the Board with certain modifications and clarifications, over the objections of Rate Counsel and other parties. PSE&G Unbundling Order, p. 100-102. The Board used the non-unanimous Stipulation as a framework for a resolution in part because it reflected a negotiated resolution of the complex and technical issues involved in that proceeding. Id. The key elements of the resolution, including the transfer of generation assets, were specified in the Board's findings and directions, which included the following:

- 27) In order to ensure that PSE&G does not retain any risks or liabilities associated with the electric generation business after the Generating Facilities have been transferred, the Board hereby orders that all contracts (except for the NUG contracts) associated with the electric generating business, including, but not limited to, wholesale electric purchase and sales agreements, fuel contracts, real and personal property interests, and other contractual rights and liabilities, be transferred from PSE&G to [PSEG Power] simultaneous with the transfer of all generating assets, and substitute [PSEG Power] as the party(s) to any such contracts.

PSE&G Unbundling Order, p. 123 (emphasis added). This language reflects that a fundamental element of the transaction was a complete transfer of the generation assets, including the risks of ownership and operation. In other words, PSEG Power’s assumption of those risks was recognized as an essential element of a transaction that allowed them to earn unregulated returns on the assets being transferred.

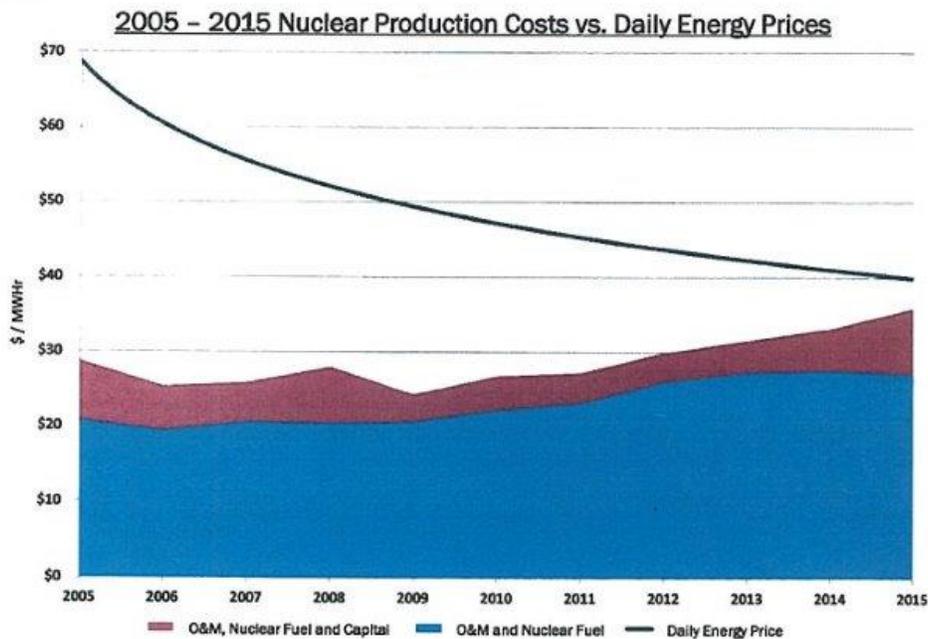
By 2005 it became clear that the generation plants that had been transferred to PSEG Power in 2000 had been grossly undervalued. The deregulated plants were making far more money than expected in the wholesale markets, undermining the claim that any costs were “stranded.” During the PSEG/Exelon merger case filed in February of 2005, Board Staff’s experts filed testimony showing the appreciation of the plant value and recommended:

In light of this substantial increase in the value of the generation plants transferred, Overland recommends that PSE&G customers be allocated some portion of the merger synergy savings otherwise attributable to PSEG Power operations.¹

While PSE&G’s “stranded” costs included costs from both its nuclear and its fossil fuel plants, a review of recent data from PSEG’s nuclear plants shows that PSEG Power’s nuclear production costs were well below the daily energy prices from at least 2005 to 2013. As shown in a slide presentation prepared by PSEG in support of its request for subsidies:

¹ I/M/O the Joint Petition of Public Service Electric and Gas Company and Exelon Corporation for Approval of A Change in Control of Public Service Electric and Gas Company, and Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05
Joint Direct Testimony of Howard E. Lubow, Gregory S. Oetting, Dr. J. Robert Malko on Behalf of Staff of the New Jersey Board of Public Utilities (November 28, 2005), p. 13.

Nuclear power: lower revenues and increased production costs



Daily Energy Price is the around-the-clock price observed at the Hope Creek generating station



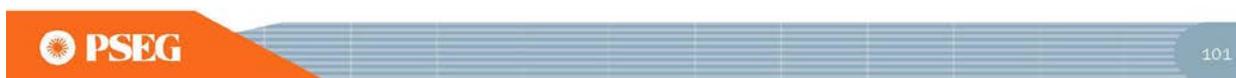
PSE&G 2016 Slide Presentation on Hope Creek, Salem 1 and 2 p.6, attached hereto as Attachment A.

The difference between the market price and production costs went straight to PSEG Power's bottom line. Thus for many years, PSEG Power made substantial profits from its nuclear plants.

Despite these profits, as of 2013, 6.6% of residential ratepayer bills were made up of charges aimed at compensating PSE&G for "stranded" costs. As PSEG explained in a March 2013 presentation to Analysts:

Our investment programs are affordable, helped by the expiration of known charges by 2017, which lower the average residential customer bill by ~ 8.7% based on today's current bill

| PSE&G Securitization & NUG Impacts (\$Millions) | | | | | |
|--|----------------|-------|------------------------|-------|------|
| PSE&G Securitization Impacts | | | | | |
| | 2013 | 2014 | 2015 | 2016 | 2017 |
| Revenues | 439 | 445 | 386 | 0 | 0 |
| Interest Expense | (46) | (30) | (11) | 0 | 0 |
| Amortization | (253) | (273) | (233) | 0 | 0 |
| Deferred Tax & Other | (140) | (142) | (142) | 0 | 0 |
| P&L Impact (GAAP view) | 0 | 0 | 0 | 0 | 0 |
| PSE&G Non-Utility Generation | | | | | |
| | 2013 | 2014 | 2015 | 2016 | 2017 |
| Revenues* | 157 | 167 | 141 | 49 | 0 |
| Expenses | (157) | (167) | (141) | (49) | 0 |
| P&L Impact (GAAP view) | 0 | 0 | 0 | 0 | 0 |
| <small>*NUG revenues reflect Feb. 1, 2013 rates</small> | | | | | |
| Typical Current Average Residential Customer Bill Impact | Securitization | ~6.6% | Non-Utility Generation | ~2.1% | |



March 1, 2013 Presentation to Analyst “PSEG Financial Review & Outlook”, by Caroline Dorsa, Executive Vice President and Chief Financial Officer, Public Service Enterprise Group, Attached hereto at Attachment B.

After 15 years, ratepayers have finally paid off the supposed “stranded costs” attributed to PSE&G’s generation assets. *See*, Public Service Electric Company SEC 10K filed February 26, 2016 (period: December 31, 2015) p. 103. Now, after many uninterrupted years of substantial profits, market forces are reducing the profits PSEG Power is able to earn from its nuclear units. As a result, Applicants are now asking ratepayers to assume the risks that PSEG Power voluntarily undertook as part of the electric industry restructuring. Moreover, the deal they are now proposing—unlike the transaction they are now seeking to modify—is entirely one-sided. Ratepayers are being asked to virtually eliminate the risks of ownership, with no

opportunity to share in the potential benefits. This result is contrary to the intent of EDECA and the balance of benefits and obligations relied upon by the Board when it approved restructuring and required ratepayers to pay \$2.9 billion in stranded costs.

B. Competitive Wholesale Electricity Markets

In order to determine whether any nuclear unit requires a subsidy, it is important to first understand the income the unit receives from regional wholesale electricity markets. New Jersey is part of a Regional Transmission Organization (“RTO”), PJM Interconnection (“PJM”). An RTO is an independent entity operating in a specific regional configuration, with operational authority for all transmission facilities under its control and exclusive authority for maintaining the short-term reliability of the grid it operates. 18 CFR §35.34(j). PJM is one of several RTOs in the United States. PJM consists of all of New Jersey as well as all or parts of twelve other states and the District of Columbia.² PJM serves 65 million people with a peak load of 165,492 MW and 178,563 MW of generating capacity.³ In addition to planning and operating the transmission system within its territory, PJM runs three separate markets, a Capacity Market, an Energy Market and an Ancillary Services Market. Nuclear units derive income from each of these markets.⁴

The Capacity Market is a three year forward looking market in which a generator agrees to provide a specific number of megawatts at a specified price generated by a PJM run auction process, called the Base Residual Auction (“BRA”). The BRA is usually held in May of each year and winning bidders are required to provide electricity on demand for an energy year

² <https://www.pjm.com/about-pjm/who-we-are.aspx>

³ <https://www.pjm.com/~media/about-pjm/newsroom/fact-sheets/pjm-at-a-glance.ashx>.

⁴ [BEGIN PSEG CONFIDENTIAL]

[END PSEG CONFIDENTIAL]

commencing in June three years later. Thus, capacity utilized in January of 2019 was the subject of the May 2015 BRA. The three-year period is intended to provide long-term price signals to attract sufficient generation infrastructure investments to assure adequate capacity within PJM. Prior to each BRA, PJM creates a demand curve based upon PJM's load forecast. That forecast is based upon peak load demands on the system. This is because heat waves or cold snaps can push the demand for electricity very high for short periods – much higher than the average level over a typical year. PJM requires more capacity than needed on an average day to cover these extreme conditions. If there is insufficient capacity, service would have to be curtailed during peak periods of demand. The value of a power plant's capacity, even if it is needed infrequently to generate energy, is the value paid for it in the capacity market. See *Fagan/Chang certification*, p. 9-10.

Capacity markets were introduced to account for the fact that some generating resources, particularly those with high operating costs that may only operate infrequently, do not earn sufficient net revenue in the energy market to cover their fixed costs. Capacity markets were designed to allow for compensation in addition to net energy revenue so that generators are paid appropriately for the value they provide to the electric system. Capacity market prices in PJM are generally expressed in dollars per megawatt.

Generators throughout PJM, or with the ability to deliver energy into PJM, submit bids at a set price for a specific amount of megawatts. It is assumed that each generator's bid accurately reflects a unit's actual costs and that the bid reflects the lowest possible amount the generator can accept in the BRA while remaining economic.⁵ The intersection of the PJM created demand curve and the supply curve establishes the BRA's closing price. Any unit that submitted a bid at

⁵ The economic viability of the auction relies on generators making bids that are not too high so as to drive up the clearing price or below actual costs to ensure clearing in the BRA, but ultimately suppressing the clearing price.

or below the clearing price clears the auction. Significantly, all units are paid the clearing price, regardless of the unit's bid into the BRA. *Id.* at p. 10. For example, if the unit bid \$5.00 per megawatt per day, and the ultimate clearing price is \$150.00 per megawatt per day, the unit receives \$150.00 per megawatt. Any unit that clears the BRA has a capacity obligation to PJM and must deliver the amount of capacity cleared in the auction to PJM on demand during the delivery year.⁶ PJM is divided into a number of load deliverability areas ("LDAs"), and the Capacity Market clears enough capacity to ensure that the peak electricity needs of each LDA will be met. This results in different capacity prices for different LDAs. Thus, the nuclear units will bid into the BRA and, assuming they clear, will receive the clearing price for the LDA in which they are located.⁷

The Capacity Market, however, is not the primary source of income for a generator operating in PJM. Rather, the generator receives the bulk of its compensation from the Energy Market.⁸ A simplistic explanation of the Energy Market is that this is the market that addresses the real time electricity needs of the system. Generators sell along a supply curve and load buys along a demand curve. The intersection of those two curves is the price of energy. PJM provides for a day-ahead and real time market with five minute interval pricing. The price is based upon locational marginal prices (LMPs), so different areas in PJM will have different prices. The LMP is the clearing price in the energy market based on the cost of generating the last quantity of electricity needed to meet demand in the moment (and location), with generating resources selected to operate in increasing order of their bids. The clearing price is paid to all accepted bidders in that specific location. To ensure the lowest production cost, PJM requires

⁶ As noted by PSEG, however, a unit can shift its capacity commitment to other units in the generator owner's portfolio.

⁷ These plants are located within the Eastern Mid-Atlantic Area Council ("EMAAC") LDA.

⁸ PSEG states that the Capacity Market represents approximately [BEGIN PSEG CONFIDENTIAL] [END PSEG CONFIDENTIAL] of the units' revenue.

that generators bid the price and amount of generation at generator-specific locations (i.e., a generator “bus”) and accepts bids from the lowest until the accepted amount meets the demand. Prices will depend upon numerous variables including demand, system conditions, available generation and available transmission within a specific zone. *Id.* at p. 10. Moreover, because the market is not an actual market, but a construct, there are various rules and administrative actions that can alter prices. The prices in the Energy Market are variable and in a given 24 hour period can fluctuate drastically. For example on January 22, 2019 the prices in the Atlantic Electric zone fluctuated within 24 hours from close to \$1,350/MWh to about\$45/MWh.⁹ Generators are paid the clearing price of the Energy Market, regardless of actual costs to generate.

Because nuclear units are relatively unable to vary output and generally run continuously at maximum output, they generally bid as price-takers in energy markets to ensure that they can continuously sell their energy, regardless of the clearing prices in either the day-ahead and real-time energy market auctions. *Fagan/Chang certification*, p. 9.

Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs. Natural gas prices have a major influence on the price that generators will receive for their output, especially in periods of relatively strong or weak demand. Therefore, changes in the price of natural gas translate into changes in the wholesale price of electricity.

PJM relies on these markets to ensure reliable electrical service throughout the RTO. To that end, PJM is constantly reviewing clearing prices of the Capacity and Energy Markets to determine if those prices are sufficient to fully compensate generators in PJM. As explained more fully below, because of its concerns, PJM has taken action to raise prices both in the Capacity and Energy Market and continues to do so. Indeed, some of that action is in direct

⁹ See screen shot from PJM NOW application, dated January 22, 2019 attached hereto as Attachment C.

response to the very issues raised by PSEG and others seeking subsidies for nuclear and other units.

PJM has also taken other actions to protect the reliability of its system. First, as explained above, any unit that clears the PJM BRA is committed three years in the future. Thus, PJM ensures that it has sufficient capacity three years from the current energy year. PJM has also established penalties to ensure that committed units actually produce energy when needed. After the abhorrent performance by generation during the 2014 Polar Vortex, PJM instituted Capacity Performance, which provides significant penalties for units failing to provide energy when called upon in the Energy Year in which they committed through the Capacity Market. Finally, PJM has the ability to enter into a “reliability must run” (“RMR”) contract on any unit within PJM. Before retiring any unit, the owner of the unit must inform PJM of its intentions to close. If PJM decides that the generating unit is needed for reliability, PJM can require the unit to remain in operation beyond its proposed retirement date—typically until system upgrades can make the unit unneeded by PJM. The generator is compensated for staying open through the RMR contract. *Id* at p. 36.

C. The ZEC Legislation

The ZEC legislation was initially considered by the Legislature in late 2017. On December 4, 2017 the Senate Energy and Environment Committee and the Assembly Telecommunications and Utilities Committee held a joint session to discuss “Strategies to Prevent the Premature Retirement of Nuclear Power Plants.” On December 14, 2017, S3560/A5330 was introduced to establish a “Nuclear Diversity Certificate Program.” Additional hearings were held on December 20, 2017, with a substantial number of witnesses testifying on both sides. The primary supporter of the legislation, and the first witness other than the sponsors

at the hearings, was PSEG President Ralph Izzo.¹⁰¹¹ In the end, S3560/A5330 did not pass. The 2016-2017 Legislature adjourned without the bill's enactment.

However, the bill came back in the 2018 legislative session. Re-branded as “Zero Emissions Credits,” the new bill, S877/A2850 was introduced in January, 2018. Initially, other than the change in the name of the Certificates, the bill was virtually identical to the bill that had not been enacted in the prior Legislature. Subsequently, there were a number of changes to the legislation. Several clean energy provisions were added and then removed to a separate bill.

There were also a number of hearings held in the Senate Energy and Environment Committee, the Assembly Telecommunications and Utilities Committee and the Senate Budget and Appropriations Committee throughout January and February, 2018. Throughout all of these hearings, the sponsors of the bill described it as one that created a process in which financial records would be submitted to the BPU. BPU would then make a determination about the need for ZECs, and, if so, the amount of any subsidies. For example, at the hearing before the Senate Energy and Environment Committee on January 25, 2018, Primary Sponsor Senate President Sweeney stated (at 16:46): “This creates one thing – a process of review where PSEG will show their books to the BPU and BPU has the authority and ability to make a determination at that point. There is no guarantee here.”

A substantially identical bill, with the clean energy provisions omitted (S2313/A3724) was ultimately passed on April 12, 2018 in both the Assembly and the Senate. The legislation was signed into law by the Governor on May 23, 2018.

¹⁰ See, e.g. Transcript of December 4, 2017 Joint Committee Meeting, p. 8-13, available at <https://www.njleg.state.nj.us/legislativepub/pubhear/senatu12042017.pdf>; and Transcript of December 20, 2017; and Transcript of December 20, 2017 Joint Committee Meeting, p. 5-10, available at <https://www.njleg.state.nj.us/legislativepub/pubhear/senatu12202017.pdf>.

¹¹ Rate Counsel reserves its right to argue in the event of an appeal that the ZEC statute is special legislation prohibited under Article VII, Section 7, Paragraph 9 of the New Jersey Constitution.

The ZEC statute provides for substantial ratepayer-funded subsidies for a limited number of nuclear units, to be selected by the Board, for an indefinite period of time. The legislation directs the Board to create a mechanism for the issuance of ZECs, which represents “the fuel diversity, air quality, and other environmental attributes” of one megawatt hour of nuclear generation. N.J.S.A. 48:3-87.4. The program is to be funded through a “non-bypassable, irrevocable” charge of four-tenths of one cent per kilowatt hour imposed on all retail distribution customers of the New Jersey’s electric distribution utilities. N.J.S.A. 48:3-87.5(j)(1). According to estimates presented at the legislative hearings, the surcharge would result in collections of approximately \$300 million annually from the State’s electric distribution customers.¹² These amounts will be deposited into accounts, and will be used exclusively to pay for ZECs and implementation costs.

Nuclear power plants were required to apply to the Board no later than December 19, 2018 to participate in the program. N.J.S.A. 48:3-87.5(c). In order to qualify, a plant must meet the criteria specified in the ZEC statute, including the following:

1. The plant must be licensed to operate by the United States Nuclear Regulatory Commission through at least 2030.
2. The applicant must demonstrate that the plant “makes a significant and material contribution to the air quality in the State by minimizing emissions that result from electricity consumed in New Jersey” and that retirement of the plant would “significantly and negatively affect New Jersey’s ability to comply with State air emission reduction requirements.
3. The applicant must demonstrate that the plant’s “fuel diversity, air quality and other environmental attributes” are at risk of loss because, based on projected financial results, the plant “will cease operations within three years unless the nuclear plant experiences a material financial change;” and

¹² E.g., Remarks of Stefanie A. Brand, Director, Division of Rate Counsel, Regarding S877 and A2850 (Establishes Nuclear Diversity Certificate Program) Presented at the Joint Meeting of the Senate Budget and Appropriations Committee and the Assembly Telecommunications Committee, p. 2 (Feb. 22, 2018), available at: https://www.state.nj.us/rpa/docs/S877_A2850_testimony_2_22_2018.pdf.

4. The applicant must certify that the plant does not receive other direct or indirect payments that eliminate the need for a subsidy. N.J.S.A. 48:3-87.5(e).

The statute provides a 120-day period, ending on April 18, 2019, to review the applications and prepare a rank-ordered list of qualified units. N.J.S.A. 48:3-87.5(e).

In ranking the units determined to be eligible, the Board is required to consider “how well” each unit satisfies the qualification criteria, as well as “other relevant factors such as sustainability or long-term commitment to nuclear energy production in a manner that supports New Jersey’s cost-effective transition to a zero carbon energy supply.” N.J.S.A. 48:3-87.5(e). Based on this ranking, the Board is directed to select units beginning with the top-ranked unit, and continuing in rank order until the point at which the addition of the next-ranked unit would cause the electricity produced by all qualified units to exceed 40 percent of the total MWh of energy distributed by New Jersey’s electric distribution utilities in Energy Year 2018. N.J.S.A. 48:3-87.5(g)(1).

The selected units become eligible to receive ZECs for an initial eligibility period that runs through the end of the energy year when the unit is selected, and three additional energy years thereafter. N.J.S.A. 48:3-87.5(h)(1). Thereafter, the selected units may be re-certified for additional eligibility periods of three energy years. N.J.S.A. 48:3-87.5(h)(2).

Beginning with initial qualification period, the selected units receive ZECs based on the actual numbers of MWhs of electricity they generate. N.J.S.A. 48:3-87.5(g) (2). The State’s electric utilities are required to purchase the ZECs on a monthly basis, with payment for the ZECs purchased during each energy year to follow within 90 days after the end of the energy year. N.J.S.A. 48:3-87.5(i)(2). The amount paid per ZEC is determined based on the total amounts contained in the accounts established by the utilities pursuant to the ZEC statute. The

value of the ZECs awarded during each energy year is determined by dividing the total amounts held in those accounts at the end of that energy year by the greater of: (1) 40 percent of the total number of MWh distributed by the electric public utilities in the State during that energy year, and (2) the actual numbers of MWh generated by the selected units during the energy year.

N.J.S.A. 48:3-87.5(i)(1). If a selected unit receives direct or indirect payments as a result of state or federal action for its “fuel diversity, resilience, air quality or other environmental attributes” the amount of such payments is deducted from the amount that would otherwise be paid for that unit’s ZECs. N.J.S.A. 48:3-87.5(i)(3).

The ZEC statute establishes a rate of four-tenths of one cent per-kilowatt hour. The Board may modify the charge in effect during subsequent eligibility periods if the Board finds that a lower charge will be sufficient to prevent the retirement of the selected units. N.J.S.A. 48:3-87.5(j)(3)(a). Such determinations must be made by the Board no later than 13 months prior to the applicable eligibility period. N.J.S.A. 48:3-87.5(j)(3)(a).

Selected units are required to certify annually they will operate at full capacity except for maintenance and refueling outages, for the duration of the then current eligibility period. N.J.S.A. 48:3-87.5(h) (3). However, the ZEC statute included provisions excusing a unit from performance for reasons that include “significant” new taxes or assessments, any state or federal law that materially reduces the value of ZECs, the Board’s exercise of its discretion to reduce the per-kilowatt-hour charge provided in the ZEC statute, or required capital expenditures exceeding \$40 million. N.J.S.A. 48:3-87.5(k)(1).

COMMENTS

A. The Applications Overstate the Likely Future Costs of the Units

On the cost side of the Applicants' claimed shortfalls, they have included significant costs related to operational and market risks that are speculative and inappropriate to charge captive regulated ratepayers. They also propose to recover capital costs on a cash flow basis over one year in violation of both basic ratemaking principles and sound accounting practice. In addition, some of the claimed operational and maintenance costs are improperly included or inflated. These defects are summarized below. As Ms. Crane's Certification explains, while both Applicants have submitted cost estimates, for Salem I and Salem II, PSEG is both the majority owner of and the entity with sole authority to make retirement decisions with regard to these two units. Accordingly, PSEG's submission addressed all elements of the application for 100% ownership of the units, with additional supporting material from Exelon. *Crane Certification*, p. 2, 3-4. For these reasons, Ms. Crane's Certification focuses on PSEG's submission, while noting that Exelon's submission reflects similar deficiencies. *Crane Certification*, p. 4, 24-25. The discussion below will follow this same approach.

1. "Costs" of Operational and Market Risks.

The ZEC statute requires applicants to provide costs, including the "the cost of operational risks and market risks that would be avoided by ceasing operations" N.J.S.A. 48:3-87.5 (a). "Operational risks" are defined in the statute as "the risk that operating costs will be higher than anticipated because of new regulatory mandates or equipment failures and the risk that per-megawatt-hour costs will be higher than anticipated because of a lower than expected capacity factor" Id. Market risks include "the risk of a forced outage and the associated

costs arising from contractual obligations, and the risk that output from the nuclear power plant may not be able to be sold at projected levels.” Id.

The Applicants’ claimed shortfalls include significant “costs” related to these risks. *Crane Certification*, p. 8. Neither category reflects actual, verifiable costs. Both are structured as cost “cushions” designed to protect the Applicants from potential higher costs or lower revenues. *Crane Certification*, p. 10.

With regard to “operational risk,” [BEGIN PSEG CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[END PSEG CONFIDENTIAL]. *Crane Certification*, p. 8.

[BEGIN PSEG CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [END PSEG CONFIDENTIAL]. *Crane Certification*, p. 8-9.

The methodologies used for both operating and market risk result in speculative and unverifiable costs. As noted, operational risk was estimated by [BEGIN PSEG CONFIDENTIAL] [REDACTED] [END PSEG CONFIDENTIAL] This

methodology assumes that operational risk will only add to the costs of operation. However it is just as likely that costs will be lower. While PSEG's estimates may be the best indicator of expected future costs, it would be unreasonable to assume that there is no likelihood costs will be lower. Since PSEG did not make any adjustments to reflect this possibility, its claimed "cost" of operational risks is one-sided and would place an unreasonable burden on ratepayers. *Crane Certification*, p. 10.

PSEG's claimed "cost" of market risk is also flawed. This methodology provides virtually a guarantee that the claimed "cost" will cover all contingencies. As is the case with operational risks, the ZEC statute does not provide for ratepayers to be guarantors for all possible contingencies relating to market risks. *Crane Certification*, p. 11. Further, any consideration of market risk must consider the history of these deregulated units. As discussed in the Background section above, the nuclear units at issue have been deregulated for approximately 20 years. At the time the State's electricity markets were restructured and these three units were transferred to an unregulated entity, ratepayers paid hundreds of millions of dollars to compensate shareholders for the risk that market prices would not be high enough to allow the owners to recover their investments at the values then reflected on the utilities' books. However, the units have in fact done very well, earning profits that have been significantly higher than anticipated. *Crane Certification*, p. 11. These results highlight the unreasonableness of reflecting a "cost" that is, effectively, a guarantee against market risks.

Moreover, as noted by Ms. Crane, in 2009 PSEG requested authorization to extend the licenses of all three units. At that time, PSEG presumably evaluated the risks of continued operation and was satisfied that the risks were justified by the expected level of earnings. Now that market conditions have changed, it would be unreasonable for ratepayers to provide a

guarantee against all risks without considering the substantial benefits that PSEG and Exelon have received in the past. *Crane Certification*, p. 11.

In summary, the asserted “costs” of operation and markets risks are based on one-sided methodologies that essentially provide a guarantee that all contingencies will be covered, with no consideration of the possibility that costs will be lower, or revenues will be higher, than PSEG’s current estimates. The “costs” are also inflated because they do not consider the substantial benefits the units’ owners have enjoyed in the past as a result of their ability to earn unregulated returns. For these reasons, the Applicants have not sustained their burden of demonstrating the claimed “costs” of operational and market risks. If the Board were to allow the Applicants to receive subsidies that include the “costs” of risks, those subsidies should also reflect the speculative and unbalanced nature of PSEG’s estimates, and take into account the prior benefits enjoyed by shareholders.

2. Inclusion of Capital Expenditures as “Costs.”

As noted, the Applicants’ requests for subsidies are presented on a “cash flow” basis, including capital expenditures. The Board must consider the appropriateness of this approach as a basis for recovery from captive ratepayers, as well as the reasonableness of the expenditures included in the Applicants’ request.

As the Board is aware, under traditional ratemaking, capital investments are not recovered in the year they are made. They are recovered over the useful lives of the underlying assets, and investors are provided the opportunity to earn a return on their investments. *Crane Certification*, p. 12-13. The cash flow approach proposed by PSEG and Exelon provides for immediate recovery of capital investments. This means that each year, they would be relieved of the risks associated with investments made that year. *Crane Certification*, p. 13. The impact of

this on the Applicants' claimed need for subsidies is substantial. PSEG has based its subsidy request on a projected shortfall of [BEGIN PSEG CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] END PSEG CONFIDENTIAL] *Crane*

Certification, p. 13-14.

The cash-flow approach is improper for several reasons. The first is that it “violates a basic accounting principle that costs which provide a benefit over multiple years should be recovered over a multi-year period.” *Crane Certification*, p. 14. This reflects the fact that unregulated businesses do not have an expectation that capital investments will be recovered in a single year, and this is especially true of investments that are expected to remain in service for many years. The accounting principles governing capital investments have been developed to reflect this reality. Id.

Second, allowing for immediate recovery eliminates much of the risk that the investments will not be recovered. This is not even appropriate for regulated entities that have an obligation to provide service and to do so at reasonable rates. It is even more inappropriate for unregulated entities that can earn and keep unregulated returns. The cash flow approach burdens ratepayers with the worst of both worlds—funding 100% of capital expenditures for these supposedly unregulated entities, but with no right to benefit from any excess returns on those investments. *Crane Certification*, p. 15.

The cash-flow approach also results in inter-generational inequity, because current ratepayers would have to pay for investments that are expected to provide benefits many years

into the future. Further, those future benefits could all be captured by PSEG and Exelon, who could collect the costs of their capital expenditures over the next three years and then sell the plants at a profit. *Crane Certification*, p. 15.

In addition to the fundamental issues with the proposed cash-flow methodology, the Applicants have not sustained their burden of demonstrating the reasonableness of the capital projects for which they seek subsidies. As Ms. Crane noted, a detailed review of the capital projects included in the applications was not possible given the limited time for review.

However, a significant portion of the projected capital expenditures are identified as **[BEGIN PSEG CONFIDENTIAL]** [REDACTED]

[REDACTED] **[END PSEG CONFIDENTIAL]** *Crane Certification*, p. 15-16.

For these reasons, the record is insufficient to support a finding that the proposed costs are reasonable.

In addition, the PSEG and Exelon submissions do not address the appropriate time frame in which to analyze the proposed investments. The ZEC statute provides for consideration of subsidies for successive three-year periods. Even if the Board decides to grant subsidies for the initial three-year period, it would be unreasonable to assume that subsidies will continue over the remaining lives of the three units. For this reason, the Board should consider whether it is reasonable to provide subsidies that require ratepayers to fund a “business as usual” capital budget, or whether subsidies should be limited to those costs that would be necessary to keep the units in operation for the next three years. *Crane Certification*, p. 16.

overhead costs.” *Crane Certification*, p. 19. Many of these costs would not be avoided if the nuclear units were shut down. PSEG has attributed significant levels of service company costs, as well as significant corporate overhead costs, and common costs, to the nuclear units. This results in overstated costs. In considering the need for a subsidy the Board should consider only costs that are shown to result from the operation of the nuclear units. *Crane Certification*, p. 19-20.

4. Exelon Filing

As noted above, Exelon provided certain financial projections to supplement PSEG’s financial data for Salem I and Salem II. Ms. Crane reviewed these projections and found the same basic problems that she found with PSEG’s projections. With regard to costs, Exelon included substantial operational and market risks as “costs,” reflected recovery of capital expenditures in the year incurred, and included non-existent Spent Fuel Costs and significant amounts for support services and overheads. *Crane Certification*, p. 24-25. Exelon’s cost projections provide no more support than PSEG’s for the Applicants’ request for subsidies.

[BEGIN PSEG/EXELON CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] END PSEG/EXELON CONFIDENTIAL] *Crane Certification*, p. 23-24.

B. The Applications Understate the Revenues From the Units

At the same time the Applicants' overestimate costs; their claim of a shortfall understates the plants' revenues in several significant ways. The Applicants assert that future capacity and energy prices will not be sufficient to cover their costs and expenses and allow a reasonable return. However, Rate Counsel expert witnesses Robert Fagan and Maximillian Chang from Synapse Energy Economics concluded upon reviewing the Applications and discovery responses that this assertion is based on faulty data and assumptions. When they conducted a sensitivity analysis incorporating the problems with Applicants' revenue projections, as well as Ms. Crane's critique of their market and operational risk adders, they found that the plants will have positive cash flow over the next three years. Thus, the statutory criteria have not been met and the Applications should be rejected.

1. Applicants' Energy Price Projections are Understated

Energy prices fluctuate from day to day throughout the year. For this reason, any analysis of future energy prices should look at likely ranges of energy revenues that could impact the cash flow models when modeling future prices. The Applicants, however, chose to base their projected energy prices not on a range but on power price forwards for [BEGIN PSEG CONFIDENTIAL] ██████████¹³ [END PSEG CONFIDENTIAL]

As discussed by Mr. Fagan and Mr. Chang:

Using forwards from [BEGIN PSEG CONFIDENTIAL] ██████████
██████████ [END PSEG CONFIDENTIAL] skews the interpretation of the results when compared to forwards from different points in time. The period chosen may have a significant impact on the estimates of future revenues. *Fagan and Chang Certification*, P. 20.

¹³ S1-ZECJ-FIN-0004

CONFIDENTIAL] [REDACTED] **[END PSEG CONFIDENTIAL]** than the prices projected by the Applicants. Thus, by **[BEGIN PSEG CONFIDENTIAL]** [REDACTED] **[END PSEG CONFIDENTIAL]** the Applicants' projections of future energy prices are too low, which skews the analysis of whether their financial situation will cause them to shut down. By failing to provide a sufficient range of reasonable revenue projections to allow the Board to adequately assess the financial condition of the units, the Applicants have failed to meet their burden to demonstrate that a ZEC is warranted.

The Applicants' analysis of future energy prices is also faulty because they failed to analyze the price impacts if only one or two of the units shuts down, rather than all three. The retirement of one of the three units may result in higher prices for the remaining two units. The upward pressure on prices that the closing of one plant will have may eliminate the need for a ZEC subsidy for the other two plants. As Fagan and Chang pointed out:

The PJM market is a dynamic system where changes in one unit may impact the prices paid other units. Specifically, if one of the units retires that would impact the profitability of the remaining two units. PA Consulting stated that it modeled the impact on emissions and fuel diversity and did not model the impact of retiring one unit on the remaining two units.¹⁵ This appears to be a critical question since the Applicants are requesting a subsidy for all three units. Nor did the Applicants account for this impact in its energy and revenue forecasts provided in the application. We believe that the retirement of one or more of the units will have a dramatic impact on the profitability analysis of the remaining units, however this information is missing in the Applications. *Fagan and Chang Certification*, P. 33.

Interestingly, PSEG's own cash flow analyses of its nuclear units include **[BEGIN PSEG CONFIDENTIAL]** [REDACTED] **[END PSEG CONFIDENTIAL]**. However, the modeling done

¹⁵ RCR PS S1 E 00019

¹⁶ S1-IUD-0004 Confidential

for the applications does not include such an analysis. The Board must make its decision based on a full record relevant to the proceeding. Whether the closure of one plant makes the remaining nuclear plants profitable, thus mitigating the need for ZEC, is relevant and necessary information for the Board to make a final determination.

Thus, the Applicants have failed to provide a reasonable range of energy revenue projections that would enable the Board to adequately assess the financial condition of the unit. Their energy price projections are understated which has the effect of skewing the analysis of their revenues. This flaw means that they have not met their burden of demonstrating that the award of ZECs to any of their units is warranted.

2. Applicants' Capacity Price Projections are Understated

The Applicants' projections of future capacity prices are also understated. **[BEGIN PSEG CONFIDENTIAL]** [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] **[END PSEG CONFIDENTIAL]**.

For comparison purposes, the Board's guidance for the offshore wind bids asks bidders to use default capacity prices by EDC zone as default values for the offshore wind bid cost-benefit

¹⁷ RCR-PS-S1-E-0003

¹⁸ RCR-PS-S1-E-0003

¹⁹ RCR-PS-S1-E-0003. These proposal are discussed in greater detail below

analyses.²⁰ The BPU's guidance values are \$190/MW-day for the PSE&G zone and \$165/MW-day for the Atlantic Electric Zone.²¹

Moreover, relative to historical prices, the Applicants' projection of future BRA prices is [BEGIN PSEG CONFIDENTIAL] [REDACTED] [END PSEG CONFIDENTIAL] the historical average from selected BRAs. The BRA prices have been set for the next three years (through June 2022). In reporting historical capacity revenues, the Applicants adjusted their BRA prices for incremental auction results from the 2020/2021 auction and previous auctions as well. FERC has allowed PJM to delay the 2022/2023 auction from May until August to allow PJM to finalize changes in the capacity market construct as discussed further below. The anticipated changes are generally expected to raise prices, but that change is not reflected in the Applicants' analysis. Thus, as with their projections of future energy prices, the Applicants' future capacity price assumptions are low. This has the effect of skewing their analysis of the units' financial conditions.

There are also omissions from the analysis of future capacity prices that should be taken into account. Specifically, [BEGIN PSEG CONFIDENTIAL] [REDACTED]
[REDACTED]
[REDACTED] [END PSEG CONFIDENTIAL] Hope Creek appears on the NYISO generator list.²² The fact that Hope Creek apparently provides some of its capacity to NYISO indicates that PSEG would need to supplement some portion of Hope Creek's nuclear capacity in PJM with other units. [BEGIN PSEG CONFIDENTIAL] [REDACTED]

²⁰ Attachment Seven: Standard Inputs for Cost-Benefit Analysis. Page 68. Available at <https://nj.gov/bpu/pdf/boardorders/2018/20180917/9-17-18-8G.pdf>

²¹ Ibid.

²² <http://mis.nyiso.com/public/htm/generator/generator.htm>

[REDACTED]
[REDACTED] [REDACTED] [REDACTED]
[REDACTED]
[REDACTED] [END PSEG CONFIDENTIAL]. However, these revenues were not included in the applicants' analysis.

The Applicants also failed to consider a number of recent policy changes on the state and federal level that may impact either demand and/or energy and capacity prices. These include the impact of New Jersey re-joining the Regional Greenhouse Gas Initiative (RGGI), the 1100 MW of offshore wind that is anticipated to come online in 2021 (and the 3500 MW 2030 goal), and the recent legislative mandates regarding energy efficiency and renewable portfolio standards. All of these programs will likely have some effect on future energy and capacity revenues realized by these plants. Yet they were ignored in the Applicants' analyses. For these reasons, the analyses are flawed and the Applicants have failed to meet their burden of demonstrating the need for ZEC subsidies.

3. The Applicants Fail to Take into Account Other Revenues that Should be Included.

a. The Applicants Fail to Include Hedging Revenues

PSEG has understated the revenues associated with the three nuclear units by excluding hedging revenues. As noted by Ms. Crane, both PSEG and Exelon enter into hedges such as [BEGIN PSEG CONFIDENTIAL] [REDACTED] [END PSEG CONFIDENTIAL] to mitigate the uncertainty of revenues in upcoming years. However both companies excluded revenues from hedging activities in their revenue forecasts. *Crane Certification*, p. 20. PSEG stated in a discovery response that, [BEGIN PSEG

²³ <https://www.northjersey.com/story/news/environment/2017/05/31/coal-power-plants/355425001/>

CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED] [END PSEG CONFIDENTIAL] Exelon stated that its hedge contracts are not usually tied to a specific unit. *Crane Certification*, p. 20.

Excluding hedging revenues overstates the required subsidies for two reasons. First, as Ms. Crane explained, even though the hedge contracts may not be tied to specific units, the three nuclear units provide “an energy source that is integral to the hedging positions taken by the two Companies.” *Crane Certification*, p. 20. Second, the costs of hedging activities were implicitly included in determining the claimed cost of market risk, and thus the benefits of hedging should not be excluded from the calculation of revenues. As noted in PSEG discovery responses

[BEGIN PSEG CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [END PSEG CONFIDENTIAL] *Crane Certification*, p. 20-21. Since both Applicants actually receive hedging revenues related to the nuclear units, and hedging-related costs were considered as part their claimed need for subsidies, hedging revenues should be included in evaluating the need for subsidies.

b. The Applicants Fail to Consider Additional Tax Benefits

Neither of the Applicants considered the impact of the Tax Cuts and Jobs Act of 2017 (“TCJA”) on their need for subsidies. The TCJA, which became effective January 1, 2018, had a major impact on the costs of both regulated and non-regulated corporations. As Ms. Crane explained, TCJA reduced the corporate tax rate from 35 percent to 21 percent. This not only

reduced corporations' current tax liabilities, but also created millions of dollars of benefits in the form of excess deferred income taxes. *Crane Certification*, p.21.

Excess accumulated deferred taxes result from the difference in the taxes recorded pursuant to Generally Accepted Accounting Principles (“GAAP”) and taxes actually paid to the Internal Revenue Service (“IRS”). *Crane Certification*, p. 21.²⁴ As Ms. Crane explained, corporations including the Applicants recorded deferred income taxes assuming the 35 percent tax rate would be in effect in the future. As a result, companies found themselves with millions of dollars of excess accumulated deferred income taxes that had been recorded at the prior federal income tax rate of 35 percent but are now expected to be paid at the lower 21 percent rate. Regulated public utilities are required to return the resulting excess amounts to ratepayers. However, for unregulated entities, the impact resulting from the change is immediately reflected in their income statements. *Crane Certification*, p. 22.

In 2017, following the enactment of TCJA, both PSEG and Exelon recorded credits to net income. PSEG recorded benefits of approximately [BEGIN PSEG CONFIDENTIAL] [REDACTED] [END PSEG CONFIDENTIAL] in 2017 due to excess accumulated deferred income taxes for the Hope Creek and Salem nuclear units. While Exelon has not provided the amount of the credit it took due to excess accumulated deferred income taxes for its share of Salem 1 and Salem 2, it is reasonable to assume that it was proportionate to the credit taken by PSEG. *Crane*

²⁴ As an example, companies are allowed to depreciate certain assets on an accelerated basis, thus “front loading” depreciation expense in the early years of the asset’s useful life for tax purposes. However, pursuant to GAAP assets are depreciated based on “straight line” depreciation over the asset’s full useful life, and the taxes recorded under GAAP are based on straight-line depreciation. This results in higher taxes being recorded pursuant to GAAP than the company is actually paying during the early years of the asset’s useful life. The reverse occurs after the asset is fully depreciated for tax purposes. The cumulative amount of taxes that have been recorded pursuant to GAAP but not yet paid to the IRS is known as accumulated deferred income tax.

Certification, p. 22. Since neither entity is subject to rate regulation, both have retained the income that resulted from the TCJA tax cut. This substantial income is directly related to the Applicants' ownership of the Hope Creek and Salem generating units, and should be taken into account as part of the Board's consideration of the need for subsidies. *Crane Certification*, p. 22-23.

There are also other tax benefits retained by the Applicants that should be offset against any subsidies. All three units are owned by limited liability companies ("LLCs"), which pass their profits and losses through to the LLC members. Since both PSEG and Exelon file consolidated income taxes, losses incurred by any LLC member can be used to offset income earned by other entities the consolidated tax group. This can be especially beneficial when the consolidated tax group includes a regulated utility with significant taxable income. As Ms. Crane noted, PSEG's regulated utility affiliate just concluded a base rate case which can be expected to provide substantial profits than can be offset with other affiliates' tax losses over the next 12 months. This and other tax benefits available to both PSEG and Exelon should be considered in the Board's analysis of the need for subsidies. *Crane Certification*, p. 23.

c. The Applicants Fail to Address Changes in PJM's Wholesale Market that May Impact Revenue for These Units.

PJM relies on markets to ensure reliable electrical service throughout the RTO. To that end, PJM is constantly reviewing clearing prices of the Capacity and Energy Markets to determine if those prices are sufficient to fully compensate generators in PJM. Because of these concerns, PJM has taken action to raise prices both in the Capacity and Energy Market and continues to do

so.²⁵ Indeed, some of that action is in direct response to the very issues raised by PSEG and others seeking a subsidy for nuclear and other units, while other actions are in direct response to actual or proposed subsidies.

Many of the proposed changes pending at PJM or FERC will also have upward impacts on Energy and Capacity Markets. Applicants did not adequately consider any of the following when projecting future energy and capacity prices. In failing to do so, Applicants' future energy projections likely underestimate the income the units will receive from the Energy and Capacity Markets.

d. PJM Energy Price Formation

PJM established the Energy Price Formation Senior Task Force in April of 2018 to address instances where “operators commit resources to ensure reliability but these commitments are not reflected through market clearing prices such that those prices can be suppressed and result in undesirable outcomes.” April 11, 2018 letter from Andrew L. Ott, President and CEO to PJM Stakeholders.²⁶ Grounded in a desire to transparently reflect the cost of ensuring reliability and resiliency, PJM proposed a change to the Energy Markets that would raise prices received for all generators.

PJM has advised that it is anticipated that on February 12, 2018 the PJM Board will direct PJM staff to file PJM's proposal. PJM's proposal will result in an increase in Energy and Reserve Market revenues of approximately \$1.92 billion. PJM Price Formation Paper, dated

²⁵ Indeed, Applicants wrote to the PJM Board of Managers on January 29, 2019 asserting that, “PJM's current wholesale power market design fails to reflect the full value of resources providing services, resulting in inaccurate price signals that undermine efficient investment by our companies . . . [the current] reforms provide modest incremental change, but fall short of the fundamental changes that are needed to support baseload electric generator units over the long-term. <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20190130-final-joint-letter-to-pjm-board.ashx?la=en> Thus, while seeking ZECs in New Jersey, Applicants urge PJM to raise prices in the PJM wholesale markets, which may mitigate any need for ZECs.

²⁶ <https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/postings/20180412-pjm-board-letter-regarding-energy-market-price-formation.ashx?la=en>

December 14, 2018.²⁷ While PJM assumes some decrease in capacity market prices (\$440 million to \$1.5 billion),²⁸ it is clear that energy market revenues will increase the overall revenue for generators. PJM has stated that it intends to file its Energy Price Formation position at FERC within the next two months, and that the result of that filing will be an increase in energy market revenues for all three units.

e. Changes to the Minimum Offer Price Rule to Reflect State Public Policy Initiatives

In 2006, after extensive negotiations, a settlement was reached creating the Reliability Pricing Model (“RPM”) for the PJM capacity market. It was approved by the FERC and incorporated into PJM’s tariff.²⁹ Pursuant to the 2006 Order, PJM operates two types of capacity auctions – the base residual auction held three years in advance of when the capacity would be needed and the incremental auction allowing the load serving entity (“LSE”) to purchase additional capacity if needed to meet unexpected demand. An LSE can choose not to participate in the auctions by using the Fixed Resource Requirement (“FRR”) alternative option allowing the LSE to directly contract with generation resources and be responsible for satisfying all capacity obligations in its service territory.

The 2006 Order also created mechanisms to prevent market manipulation in those auctions including a rigid price cap on all offers and a Minimum Offer Price Rule (“MOPR”). The MOPR was designed to curb monopsony power, the power of a buyer facing many sellers with little or no competition from other buyers. To avoid artificially low prices sure to clear the

²⁷ <https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-04-price-formation-paper.ashx>.

²⁸ That assumption does not include upward pressure on capacity market prices that will likely result from the other initiatives listed below.

²⁹ See: *PJM Interconnection L.L.C.*, 117 FERC ¶61, 331 (2006), the “2016 Order”.

auction, the MOPR seeks to identify uneconomic offers and “mitigate” them by raising them to a price that more accurately approximates their net costs.

In April 2018, in the face of an increasing desire by states to enact policies to preserve certain resources despite the market outcomes, including nuclear power plants, PJM proposed revisions to RPM. PJM described the changes as designed to address the “impacts” and “adverse effects” of these state policies on the RPM markets.³⁰ PJM proposed “capacity repricing,” which would allow resources receiving out-of-market payments as a result of state programs (“state-sponsored resources”) to bid into the auction and, if they cleared, receive an RPM capacity payment. PJM would then subsequently ‘re-price’ the offers of these resources to an administratively-set floor, and rerun the auction to set the clearing price for all resources so that the subsidized prices bid by the state-sponsored resources did not set the clearing price.³¹ In the alternative, PJM proposed a modified MOPR that would increase the offer price of certain resources.

In June 2018, FERC rejected PJM’s repricing proposal and the amended MOPR. The Commission remanded the matter back to PJM with a preliminary finding that a further expanded MOPR and a resource-specific FRR could be just and reasonable.³² While the original MOPR had only previously been applied to newly constructed natural-gas fired resources which had not yet cleared PJM, the expanded MOPR cited by the Commission would apply without exception to all new and existing resources. The FRR alternative (“FRRa”) would remove a state-sponsored resource from PJM’s RPM, “along with a commensurate amount of load.”³³

³⁰ *PJM Interconnection L.L.C.*, Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, at 1, Docket No.: ER18-1314 (April 9, 2018).

³¹ See: the 2016 Order at ¶s 35-42.

³² *Id.* at ¶s 158 & 160.

³³ *Id.* at ¶ 160.

FRRa resources would not receive a payment from RPM and the commensurate amount of load would not make capacity payments to those resources through PJM. The Commission held that the FRRa should increase transparency by showing “which capacity costs are the result of competition in the capacity market and which capacity costs are being incurred as a result of state policy decisions.”³⁴ The BPU and others filed a request for rehearing of the June Order, which remains pending before the Commission.

f. Grid Resiliency and Reliability

On September 28, 2017, the US Secretary of the Department of Energy (“DOE”) submitted a rule-making proposal to the FERC pursuant to Section 403 of the DOE Organization Act.³⁵ Citing to a DOE Staff Report on electric markets and grid reliability, the Secretary of Energy directed FERC to order all regional transmission organizations to develop tariffs that would require load-serving entities to purchase energy from defined “reliability and resilience resources”, and allow recovery of the costs and return-on-equity for these resources.³⁶ Such resources were narrowly defined in the proposed rule as essentially only coal and nuclear facilities.³⁷ Complying with the directive from the Secretary of Energy, FERC initiated a rule-making proceeding.

After receipt of voluminous comments from stakeholders, on January 8, 2018, FERC terminated its rule-making proceeding and opened a new docket to further examine the reliability

³⁴ *Id.* at ¶ 162.

³⁵ 42 U.S.C. §7171 (2012). See also, 18 CFR § 35.28, Docket No. RM17-3-000 (Grid Resiliency Pricing Rule)

³⁶ See, “Staff Report” at p. 14

<https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability%200.pdf>.

³⁷ *Ibid.*

and grid resiliency of the electric markets managed by RTOs.³⁸ FERC specifically stated that part of its justification for terminating the initial rule-making proceeding was that:

“ . . . the Proposed Rule would allow all eligible resources to receive a cost-of-service rate regardless of need or cost to the system. The record, however, does not demonstrate that such an outcome would be just and reasonable. It also has not been shown that the remedy in the Proposed Rule would not be unduly discriminatory or preferential. . . .”³⁹

FERC concluded that any modification of the electric market requires a comprehensive or “holistic” examination of all resources to determine the requirements for reliability and grid resiliency.⁴⁰

As a result, FERC requested additional comments from by May 9, 2018 to respond to how grid resiliency and reliability are currently being addressed, and, how any perceived deficiencies would be corrected.⁴¹ Although the Commission has not issued its Order concerning the pending proceeding, it is very likely that generators – including nuclear facilities – could receive additional revenues if FERC finds that further mitigation of risks are needed to support the resiliency and reliability of the energy grid. Such a ruling by FERC would result in additional capacity and/or energy market profits for nuclear units and, therefore, must be considered by the Board in its review of the necessity for the ZECs requested by the Applicants.

g. Fuel Security Proposal by PJM

On March 30, 2017, PJM released its “Evolving Resources Mix and System Reliability” report (“March 30, 2017 Report”) as a result of concerns raised by various stakeholders after the

³⁸ FERC Grid Resiliency Pricing Rule, RM18-01-000 (October 10, 2017), and, Grid Resilience in Regional Transmission Organizations and Independent System Operators, AD18-07-000 (January , 2018).

³⁹ FERC Order AD18-07-000, 162 FERC § 61,012 at p. 9

⁴⁰ *Id.*, at p. 1.

⁴¹ *Id.*, at p. 19

January 2014 “Polar Vortex” weather event.⁴² During a colder-than-normal period in January 2014, the demand on the electric grid required PJM to request greater than usual operation of various types of generation units. However, certain generation units failed to respond as expected which initiated stakeholder discussions concerning grid resilience and reliability. The major conclusion of the March 30, 2017 Report was that the PJM electricity market has sufficient fuel diversity, but due to national energy policy changes and lack of uniformity in the definition of resiliency, more analysis should be conducted by PJM.⁴³

Continuing to study the resiliency of the electric market, PJM released its December 17, 2018 report, “Fuel Security Analysis: A PJM Resilience Initiative (“December 17, 2018 Report”).⁴⁴ The December 17, 2018 Report concluded that PJM has no current reliability issues, but due to more dependence on gas – fired resources, plant retirements and the availability of gas transportation services, it is necessary to determine the value of fuel secure resources.⁴⁵

At its January 24, 2019 Markets and Reliability Committee meeting, PJM announced that a new ‘Senior Task Force’ will be created to specifically address the issue of measuring the value of “fuel security attributes through competitive markets.”⁴⁶ While the task force is just beginning, its mandate to ensure fuel secure resources are properly valued will likely result in additional revenues for these units in the capacity or energy markets.

⁴² See, <https://www.pjm.com/-/media/library/reports-notice/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx?la=en>

⁴³ *Id.*, at p. 38-40

⁴⁴ See, <https://www.pjm.com/~/-/media/library/reports-notice/fuel-security/2018-fuel-security-analysis.ashx>

⁴⁵ See, <https://www.pjm.com/-/media/committees-groups/committees/mrc/20190124/20190124-item-07-fuel-security-presentation.ashx>

⁴⁶ See, <https://www.pjm.com/committees-and-groups/committees/mrc.aspx> (1/14/2019)

4. Regional Greenhouse Gas Initiatives

On January 29, 2018, Governor Murphy signed Executive Order 7 (“EO7”), which instructed the NJ Department of Environmental Protection (“DEP”) and the Board to initiate the process to have NJ return to RGGI. RGGI is a 9-state, regional program which was formed in 2005 to establish ‘cap-and-trade’ auctions to reduce carbon dioxide (CO₂) emissions.⁴⁷ Natural gas and other fossil-fueled generation facilities with capacity greater than 25 MW are allowed to purchase allowances per ton of CO₂ emitted annually. Participating states use the revenue from the auctions to promote renewable energy programs and clean energy goals.⁴⁸ Due to Governor Murphy’s directive, the DEP is currently conducting public hearings and rule-making proceedings to return the State as a participating RGGI member.⁴⁹ As further explained in the Certification of Rate Counsel’s experts, Messrs. Chang/Fagan, New Jersey’s re-entry into the RGGI Program will impact energy prices by raising the cost of competing fossil generation and should have been specifically considered by the Applicants in estimating future revenues.

C. The Applications’ Calculation of Environmental Benefits is Inaccurate

To qualify for a ZEC, an applicant must demonstrate that its “environmental attributes are at risk of loss” because it is not expected to cover its “costs and risks” and will have to shut down. N.J.S.A. 48:3-87.5(3)(a)(3). In addition, the ZEC itself is supposed to compensate the nuclear plant owners for the “emissions avoidance benefits” of the plant, which is defined as:

The benefits associated with the preservation of better air quality and other environmental attributes caused by the production of electric energy from a selected nuclear power plant, as well as the reduction in damage that would otherwise be caused by carbon dioxide or other greenhouse gases or other pollutants emitted but for the production of electric energy from a selected nuclear power plant.

⁴⁷ Ibid.

⁴⁸ See, www.rggi.org/

⁴⁹ See, www.nj.gov/dep/rules/notices.html

N.J.S.A. 48:3-87.4 (2).

To estimate this statutory criterion and justify the value of the ZEC, the Applicants retained PA Consulting to conduct emissions modeling and ERM to conduct dispersion modeling. Both modeled three scenarios: the *status quo*, the impact if only Hope Creek shuts down, and the impact if all three plants shut down. ERM used the results of the PA Consulting modeling and conducted dispersion modeling for ozone, NO_x and a spreadsheet analysis for Greenhouse gases (“GHG”).

The results of this modeling demonstrate that while GHG emissions would go up under both of the shutdown scenarios, the amounts would still come in under the 2020 targets established in the Global Warming Response Act (GWRA). N.J.S.A. 26:2c-37. Similarly, with respect to ozone, the modeling found that there would be some increase if the plants shut down, but not a significant increase. With respect to NO_x, the modeling also found an increase if the plants shut down. However, as set forth in the *Certification of Robert Fagan and Maximillian Chang*, the Applicants’ modeling suffered from significant flaws that had the effect of magnifying the likely environmental impacts. Thus, the changes that will result are likely to be even lower than portrayed by the Applicants.

ERM found that the closure of the three nuclear units would result in an increase of 12.92 million metric tons (“MMT”) of GHG, and that overall statewide emissions would be 121.6 MMT. The retirement of a single nuclear unit results in an increase of 6.85 MMT of GHG, and that overall statewide emissions would be 114.6 MMT. Both statewide totals are still below the below the statewide 2020 GWRA limit of 125.6 million metric tons (MMT). The ERM ozone modeling results indicate that the retirement of three nuclear units would increase ozone emissions by a maximum of 0.57 parts per billion (ppb). New Jersey’s 8-hour ozone standard is

70 ppb. Thus, ERM found that the three nuclear units would result in an increase of ozone impacts representing 0.8 percent of the state's ozone standard. ERM found that NOx emissions would increase by 18.3 tons per day under the three unit retirement scenario, and that these results were incorporated into the ozone modeling.

These numbers are likely overstated for a number of reasons. First, as with the PA Consulting report, ERM limited the modeling period to June 1, 2019 through May 2022. This near-term time frame limits the possible replacement resources to either existing generation and/or known capacity builds, and excludes the medium and long-term trends and initiatives in New Jersey that could affect state emissions. Most notably, it excludes consideration of the addition of 1,100 MW of offshore wind in the medium term and up to 3,500 MW over a longer term that will affect emissions and fuel diversity trends. ERM also ignored increased Renewable Portfolio Standard requirements in the medium and long-term that would result in increased renewables in the state that may help offset some loss of carbon-free emissions should one or more of the nuclear units retire. On the demand side, the PA Consulting and ERM modeling exercise did not incorporate increased energy efficiency requirements, which would help reduce demand that may also help offset some loss of carbon-free emissions should one or more of the nuclear units retire.

ERM also overstates energy sales which results in an inflated estimate of how much more generation would be needed to meet future energy requirements. ERM assumed that 2020 energy sales would be the same as the average energy sales from 2013-2017, which ERM found to be 74,548,082 MWh.⁵⁰ This represents an increase of 1.6 percent from the 2017 reported energy

⁵⁰ S1-ZECJ-ENV-0002-0011

sales of 73,382,940 MWh.⁵¹ ERM then applied a 7 percent loss factor to the sales data from the Energy Information Administration (EIA) to arrive at a net sales amount of 80,159,228 MWh for 2020.⁵² However, the 2018 PJM load forecast for New Jersey shows net energy sales for New Jersey of approximately 76,181,000 MWh for 2020.⁵³ This suggests that the ERM data may be overstating future energy sales for New Jersey by 5.2 percent compared to PJM load forecasts.

Like PA Consulting, ERM modeled all of the retirement scenarios as if the plants would close on June 1, 2019 and assumed that the Hope Creek retirement scenario also served as a proxy for the retirement of any one of the three units. This is not a realistic assumption. Each of the three nuclear units has capacity commitments for several more years and different refueling outage dates. This assumption of an early retirement skews the emissions impact that the retirement of any one or all three of the nuclear units may actually have on New Jersey in relation to the 2020 GWRA emissions threshold.

The Applicants' emissions modeling also failed to take into account [BEGIN PSEG

CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

⁵¹ ERM presented their estimated energy sales based on EIA data that is reported in calendar year. This presentation is close, but not the same as the energy year (June 1 to May 31) format that is stated in the Statute.

⁵² S1-ZECJ-ENV-0002-0011

⁵³ Table E-1 page 93. Available at <https://www.pjm.com/-/media/library/reports-notice/load-forecast/2018-load-forecast-report.ashx>. The PJM load forecast is based on information provided to PJM that should include losses.

[REDACTED] [END PSEG CONFIDENTIAL] Certainly this should have been taken into account since such a large part of the Applicants’ argument for the ZEC is that it will preserve the “environmental attributes” and “emissions avoidance benefits” of these plants. If New Jersey ratepayers are not getting those attributes or benefits because PSEG is selling the Hope Creek capacity to New York, then those values should have been included in the Applicants’ environmental modeling.

For these reasons, Applicants have failed to demonstrate that the environmental attributes of these plants justify awarding ZECs. In addition, they have failed to demonstrate that the “emissions avoidance benefits” of these plants justifies the substantial approximately \$300 million per year cost of the ZECs.

D. The Units Are Not Likely to Close in the Next Three Years

In addition to the failure to demonstrate the financial and environmental criteria necessary to justify the award of a subsidy, there are other reasons why it is not likely that these units will close in the next three years. First, as noted earlier, all three of the nuclear units have cleared in the PJM BRA capacity auctions. They are therefore committed to providing capacity in three years. While PSEG and Exelon could substitute other generation in place of their nuclear commitments,⁵⁴ replacing such a substantial amount of capacity would be costly and difficult. If they could not find sufficient replacement capacity, they would subject themselves to

⁵⁴ [BEGIN PSEG CONFIDENTIAL] [REDACTED] [END PSEG CONFIDENTIAL]

penalties under PJM’s Capacity Performance rules. Thus, the most likely scenario is that the companies would keep the plants open to meet their capacity commitments.

This likelihood is underscored by PSE&G’s actions regarding the PJM Artificial Island (“AI”) Project, which relates to transmission upgrades being considered to carry electricity from the nuclear units that are the subject of these applications.⁵⁵ The AI project has been hotly debated since 2013. In April of 2013, PJM asked for proposals from merchant transmission owners to solve stability issues coming from the nuclear plants on Artificial Island. Multiple entities, including PSE&G submitted bids. While the full details are not relevant to this discussion, there was significant debate over PJM’s selection process and its proposed resolution. Throughout the process, PSEG and its subsidiary PSE&G, argued that PSE&G’s transmission proposal was the best solution and even filing a Complaint at FERC in January of 2015 arguing that PJM’s process was improper. FERC denied that Complaint. EL15-40. At no point during that process did PSEG or PSE&G assert that there was any risk that the nuclear units would close, despite the possible expenditure of hundreds of millions of dollars to support upgraded transmission from the nuclear plants.

On July 29, 2015, the PJM Board approved the AI Project and assigned a portion of the construction to PSE&G. Subsequently, PSE&G filed a petition with FERC seeking incentive rate treatment for PSE&G’s portion of the project. See FERC Dkt. No. ER16-619. Significantly, in support of that application, PSE&G’s Senior Vice President—Delivery Projects and Construction, testified as to “what contingencies outside of PSE&G’s control could cause

⁵⁵ The AI Project consists of a 230 kilovolt transmission line under the Delaware River, connecting a substation at one of the nuclear stations to a new substation to be built in Delaware.

abandonment of the AI Project?” At no point in the filing does PSE&G mention the possibility that any of the units on Artificial Island were at risk of ceasing operations.⁵⁶

There has also been contentious debate concerning cost allocation for the AI transmission project. The debate on cost allocation centers on where the electricity from Artificial Island actually flows and who benefits from the electricity. It is undisputed that the energy output from Artificial Island currently flows to ratepayers in states other than New Jersey. That is simply the nature of a grid—once the electrons are released to the grid, it is impossible to trace their path. The upgrades to Artificial Island, however, make it clear that after completion of the project, significantly more energy is likely to flow out of New Jersey to Delaware and then Maryland and Pennsylvania. PJM’s Solution-Based DFAX analysis, which is used to evaluate the cost allocation of transmission facilities,⁵⁷ determined that 99.98% of the power flow benefit should be assigned to the Delmarva Power Zone. In other words, upon completion of the AI Project, significantly more megawatts of power will flow from Artificial Island to Delaware and Maryland, further increasing the subsidies New Jersey ratepayers will pay for the benefit of Delaware, Maryland and other PJM states’ ratepayers through ZECs.

This debate continues before FERC. Through multiple filings with FERC and PJM, and numerous discussions with all parties, PSEG has never once put into question the need for upgrades to transmission from Artificial Island. In other words, PSEG never stated that PJM should reconsider this project based upon the possible closing of the nuclear units on Artificial

⁵⁶ It is significant that the question asks about contingencies outside of PSE&G’s control. Closure of the nuclear units at Artificial Island is clearly outside of PSE&G’s control, albeit within the control of its parent corporation. Nonetheless, if closure of the units was under serious consideration in 2015, it should have been listed as a possible contingency impacting construction of the AI Project.

⁵⁷ “The Solution-Based DFAX method evaluates the projected relative use of a new Reliability Project by load in each zone and withdrawals by merchant transmission facilities and through this power flow analysis, identifies projected benefits for individual entities in relation to power flows.” PJM Interconnection, L.L.C., 142 FERC ¶61,214 at P 416 (2013) (emphasis added).

Island. Certainly if the threat of closure were real, PSEG would have informed PJM and PJM would have made an assessment as to whether the AI upgrades are indeed still needed. This has not happened because PSEG has never stated as part of those proceedings its intention to close these nuclear units. This provides further evidence that these plants will not in fact close within three years.

Another reason why these plants are unlikely to close is their commitments into the PJM BRA and New Jersey's BGS. All three units have existing obligations for the PJM Capacity Market through 2022. While it is theoretically possible for the Applicants to unwind their wholesale commitments by obtaining replacement generation,⁵⁸ Exelon has noted that as a practical matter it would retire units at the end of other obligations. This would mean that realistically, the Applicants would not be practically able to retire any one of the three units until the end of May 2022. Similarly, all three units have existing capacity obligations for the NJ BGS through 2022. Again, Exelon has stated that it would retire the units only after the end of these obligations. Thus, it is unlikely the units will shut down in the next three years.

E. Other Important Considerations and Reasons to Deny the Applications

Based on the information discussed above, the Applicants have failed to meet their burden to demonstrate that they are entitled to a ZEC subsidy under the criteria set forth in the statute. However, if the Board determines that some subsidy should be awarded, the following are important considerations that must be taken into account.

⁵⁸ **[Begin PSEG Confidential]** [REDACTED] **[End PSEG Confidential]** it would be extremely difficult to replace all of the units' capacity obligations with alternative resources.

1. The Reasonableness of the \$.004/ kwh Rate

The BPU has no authority under governing law to approve an unjust or unreasonable rate. Thus, the BPU has an obligation to determine not only whether a ZEC is warranted, but also whether the rate set forth in the statute is just and reasonable. The Company argues that the rate set in the statute is immutable and that, while the BPU has authority to deny a ZEC, it does not have authority to reduce the ZEC rate if it finds that a subsidy is warranted under the statutory criteria. This is not an accurate reading of the law. It ignores substantial case law and other clear statutory mandates. See, N.J.S.A. 48:2-21(b) (which obligates the BPU to ensure that any rates it approves are “just and reasonable”) and N.J.S.A. 48:3-1 (which prohibits utilities from charging rates that are unjust or unreasonable).

The Legislature’s goal in enacting the ZEC statute was not to repeal existing principles governing electricity generation and utility rate setting, but to provide limited relief for the claimed financial hardship of nuclear plants in order to prevent them from shutting down, threatening existing jobs and environmental goals. The \$0.004 per kilowatt-hour rate set by the Legislature in the statute purports to “reflect[] the emissions avoidance benefits associated with the continued operation of selected nuclear power plants.” N.J.S.A. 48:3-87.4. However, there is nothing in the statute that quantifies those “benefits” or explains how the rate was calculated. Indeed, the statute was written before any proceedings occurred to review any factual information and before any plants were selected. Thus, there is no way that the \$0.004 rate could have been set based on any factual record establishing “emissions avoidance benefits” or analyzing what would be needed to alleviate any financial hardship sufficient to keep plants open

and avoid any purported increase in emissions.⁵⁹

There is nothing in the statute that repeals the Board's overall regulatory authority to establish rates and regulatory duty to ensure that rates are just and reasonable. To the contrary, the Legislative hearings included many statements from Legislators and proponents of the bill that demonstrate that the intent was to permit the BPU to exercise its broad discretion to look at the financial status of the plants and establish just and reasonable rates.⁶⁰ Thus, BPU must analyze, if it finds that a ZEC is justified at all, whether the \$0.004 rate is just and reasonable. Even if the statutory language appears to impose the \$0.004 rate without allowing BPU to change it, the statute cannot be read to allow approval of an unjust or unreasonable rate. As the New Jersey Supreme Court has held:

The system of rate regulation and the fixing of rates thereunder are related to constitutional principles which no legislative or judicial body may overlook. For if the rate for the service supplied be unreasonably low it is confiscatory of the utility's right of property, and if unjustly and unreasonably high (bottomed as it is on the

⁵⁹ In fact, the original version of the bill described the certificates, then called "Nuclear Diversity Certificates," as representing the "environmental and fuel diversity attributes of one mega-watt-hour of electricity" generated by a nuclear plant. https://www.njleg.state.nj.us/2016/Bills/S4000/3560_11.HTM. When the bill was reintroduced in the 2018-2019 legislative session, the certificates became known as "Zero Emission Certificates" purportedly representing the "emissions avoidance benefits" of keeping the nuclear plants open. However, even though the certificates were representing the value of different things under different versions of the bill, the \$0.004 per kilowatt hour rate remained the same. This is further evidence that the rate was not based on any particular valuation of "fuel diversity," "environmental attributes," or "emissions avoidance benefits."

⁶⁰ For example, at the hearing before the Senate Energy and Environment Committee, on January 25, 2018, https://www.njleg.state.nj.us/media/archive_audio2.asp?KEY=SEN&SESSION=2018, Primary Sponsor and Committee Chairman Smith stated (at 12:56) that the newly revised bill gives "greater powers to the BPU with regard to the request for support." Primary Sponsor Senate President Sweeney stated (at 16:46): "This creates one thing – a process of review where PSEG will show their books to the BPU and BPU has the authority and ability to make a determination at that point. There is no guarantee here." A press release issued by Primary Sponsor Senator Kip Bateman (attached) on the original version of the bill stated, "I support the checks and balances in the legislation that will allow the BPU to review PSEG's financials. This will help us to minimize the impact on ratepayers and ensure that the nuclear plants are only getting what they need to stay in the black." <https://www.senatenj.com/print/release.php?postid=36046>

exercise of the police power of the state), it cannot be permitted to inflict extortionate and arbitrary charges upon the public. And this is so even where the rate or limitation on the rate is established by the Legislature itself.

In re proposed Increased Intrastate Industrial Sand Rates, 66 N.J. 12, 23-24 (1974). *See also*, State v. Trenton, 97 N.J.L. 241, 247 (Court of Errors and Appeals, 1922) (“rates fixed by legislation must be reasonable, and to that end must be subject to judicial review.”)

Nor can there be any legitimate argument that this charge is not a “rate” that must be just and reasonable. In re Redi-Flo Corp., 76 N.J. 21, 40-41 (1978) (holding that N.J.S.A. 48:2-21(d) defines a rate from the standpoint of the consumer and that any increase that causes an increase in the consumer's out-of-pocket expenditure is a “rate increase” under the statute.) *See also*, In re Board’s Investigation of Local Exchange Carrier Intrastate Access Rates, 2012 N.J. Super Unpub., LEXIS 1430 *42 (“ The requirement for ‘just and reasonable’ rates applies whether the BPU is setting rates under a traditional methodology or under a plan of alternative regulation.” (citations omitted)). Thus, any interpretation of the ZEC statute as stripping away the power or duty of the Board to ensure that the rate charged is just and reasonable would directly conflict with existing statutory mandates that are derived from “constitutional principles.” Industrial Sand Rates, *supra*, at 23-24.

It is well established that when two statutory provisions appear to conflict, they should be harmonized and read in *pari materia* so that the meaning and purpose of each is respected. As the Appellate Division stated in In re Public Service Elec. and Gas Company's Rate Unbundling, Stranded Costs and Restructuring Filings, 330 N.J. Super. 65, 103 (App. Div 2000): “Statutory interpretations should turn on the breadth of the legislative objectives and the common sense of the situation.” County of Camden v. South Jersey Port Corp., 312 N.J. Super. 387, 396, 711 A.2d 978 (App.Div.), *certif. denied*, 157 N.J. 542, 724 A.2d 801 (1998). Also, “[o]ur task is to harmonize the individual sections and read the statute in the way that is most consistent with the

overall legislative intent." Fiore v Consolidated Freightways, 140 N.J. 452, 466, 659 A.2d 436 (1995). *See also*, Application of Saddle River, 71 N.J. 14, 17 (1976) (“our concern in interpreting the statute must be to effectuate the public policy of the state as a whole.”)

Based on these principles, unless the Board finds that a nuclear plant’s application demonstrates that the \$.0004 rate is just and reasonable, the Board must either deny the ZEC in its entirety or approve some lesser amount. There is no reading of the law or legislative intent that would allow the Board to approve a rate that it deems unjust or unreasonable. In fact, as noted above, numerous statements by the sponsors of the legislation demonstrate that the intent was not to usurp the BPU’s normal review process and standard of review. For example, at the December 20, 2017 hearing on the original version of the bill, Primary Sponsor Senator Sweeney stated: “There has been a lot of discussion about – that this is an automatic hand-out to the utility. That is not true. This bill creates a process for the BPU to review the finances of the utility to make sure that it can function and stay operational.” Tr. 12/20/17⁶¹, p. 2. *See also*, footnote 60 above. While it certainly can be argued that the statute’s language does not allow the Board to award a ZEC at a lower rate, common sense and a reading of the overall Legislative objectives of the statutes governing BPU ratemaking authority lead to the conclusion that if the Board deems the \$.0004 rate excessive then (1) awarding a lesser amount; or (2) denying the ZEC outright are the only options available to the Board to harmonize these statutes. Approving a rate the Board does not find just and reasonable is not an option that is consistent in any way with the overall legislative scheme. In re Petition of Elizabethtown Water, 107 N.J. 440, 450 (1987) (noting that “[o]ne of the BPU’s most important functions is to fix ‘just and reasonable’ rates.”).

⁶¹ <https://www.njleg.state.nj.us/legislativepub/pubhear/senatu12202017.pdf>

2. Deductions pursuant to N.J.S.A. 48:3-87.5(i)(3)

N.J.S.A. 48:3-87.5(i)(3) provides:

To ensure that a selected nuclear power plant shall not receive double-payment for its fuel diversity, resilience, air quality or other environmental attributes, the board shall annually determine the dollar amount received by the selected nuclear power plant in an energy year pursuant to a law, rule, regulation, order, tariff or other action of this State or any other state, or a federal law, rule, regulation, order, tariff or other action, or a regional compact referenced in paragraph (4) of subsection e. of this section.

Once that amount is calculated by the Board,

The number of ZEC's purchased by each electric public utility from a selected nuclear power plant for an energy year shall be reduced by the number of ZECs equal in value to the dollar amount determined by the board in this paragraph multiplied by the percentage of electricity distributed in the State by the electric public utility as compared to other electric public utilities in the State. To the extent that the board determines that a selected nuclear plant receives revenues for its fuel diversity, resilience, air quality, or other environmental attributes, the board shall immediately reduce the number of ZECs on a prospective basis consistent with the level of such revenues.

While calculating the exact dollar amount attributable to any particular factor in a market-based price is difficult, the statute makes clear that the Board must do so and must deduct that value from any ZECs awarded. This includes PJM's initiatives in Energy Price Formation (proposal to add \$1.9 billion in revenues to the PJM Energy Market); changes to the MOPR to reflect state policy initiatives (all proposals will result in higher bids into the PJM Capacity Market, which will almost certainly drive up the clearing price); Grid Resiliency and Reliability (providing generators additional revenue in the Capacity and/or Energy Markets to assign value to resiliency or reliability attributes); and Fuel Security (Providing additional revenue to address the proper value of fuel secure resources). PJM is likely to take additional actions that will raise prices in the Capacity and Energy Market, and these also should be taken into account. Similarly, New Jersey's re-entry into RGGI will provide the units with additional income.

Significantly, those additional payments will be based upon the units' environmental attributes and therefore should be deducted from any ZEC the Board awards.

Respectfully submitted,



Stefanie A. Brand

Director, Division of Rate Counsel

ATTACHMENT A



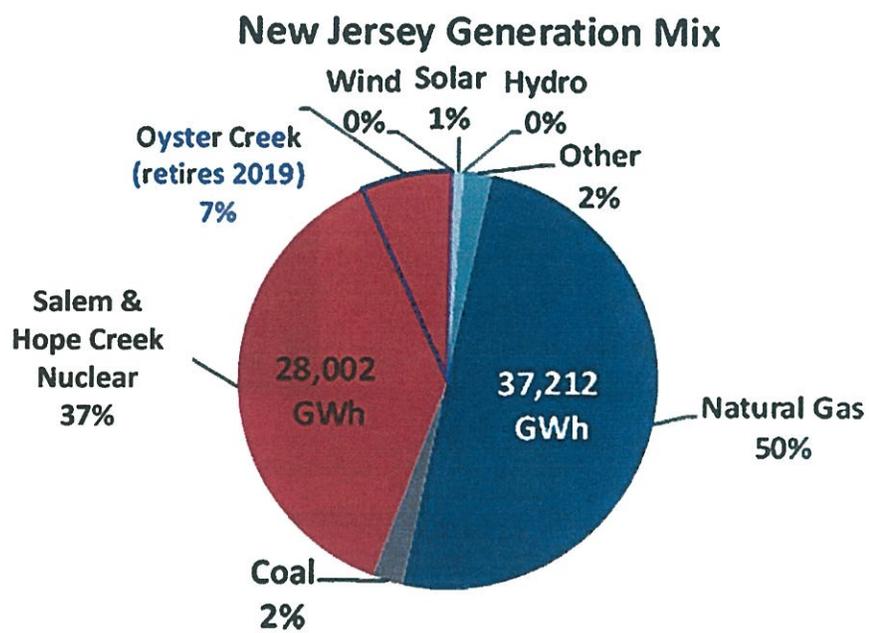
PSEG

We make things work for you.

New Jersey has consistently and publicly recognized the importance of nuclear power

- “The production and distribution of clean, reliable, safe, and sufficient supplies of energy is essential to New Jersey’s economy and way of life.” NJ Energy Master Plan 2015
- “New Jersey’s four nuclear power plants (at two sites) produce, on average, about 50 percent of New Jersey’s electric power. Because nuclear power plants do not emit greenhouse gases and criteria pollutants, nuclear power generation in New Jersey is a critical component of the State’s clean energy portfolio.” NJ Energy Master Plan 2015
- “New Jersey’s nuclear power fleet, which accounts for approximately 52% of our annual in-state generation, and has been providing emission-free, base load power for over 3 decades.” New Jersey’s comments to EPA on the Clean Power Plan, November 26, 2014
- Criticizing the EPA’s CPP, NJ argued, that (1) “the proposed rule does not sufficiently credit pre-existing carbon free nuclear power” and (2) that “the proposed rule would severely limit fuel diversity, presenting significant reliability and cost concerns.” New Jersey’s comments to EPA on the Clean Power Plan, November 26, 2014

New Jersey Electricity Generation 2015



The Value of Nuclear Energy to New Jersey

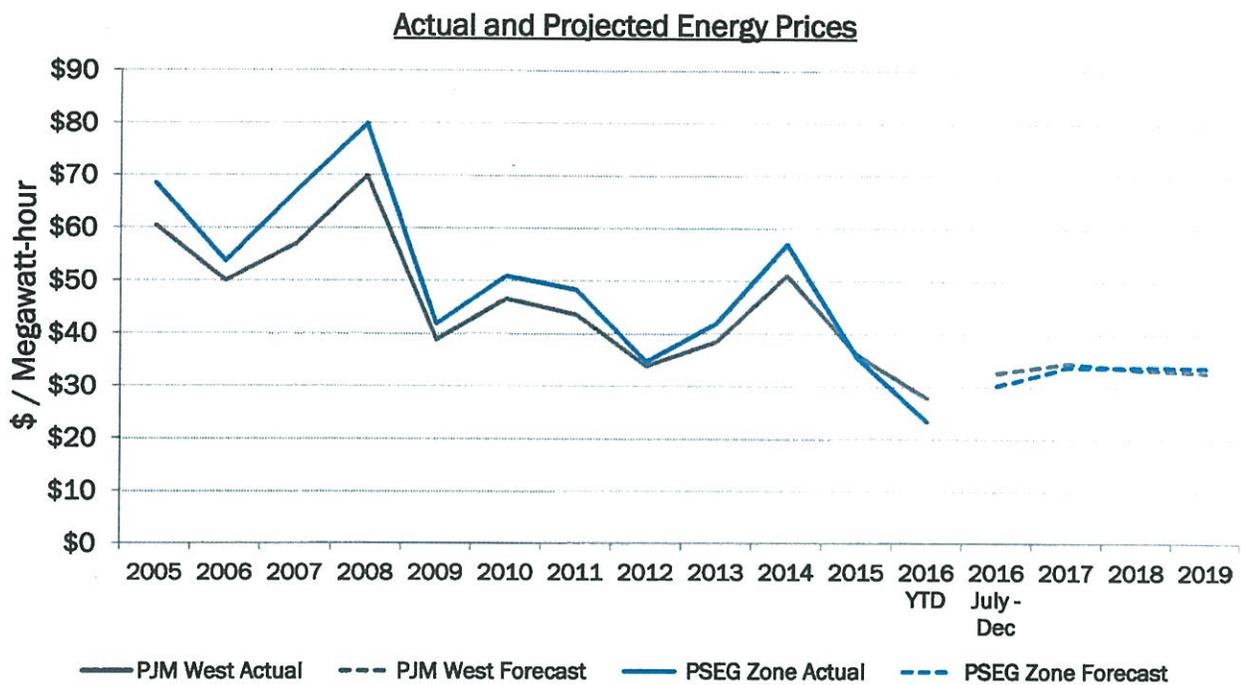
Salem and Hope Creek Stations:

- Produce 28 billion kilowatt hours – enough to for 2.7 million households
- Support over 3,100 jobs: 1,600 permanent jobs, 500 full time contractors and 1,000 contractors twice annually for refueling outages
- Annual payroll > \$175 million
- Average salary ~\$99,000/year
 - Plant salaries more than 35% higher than average in Salem County



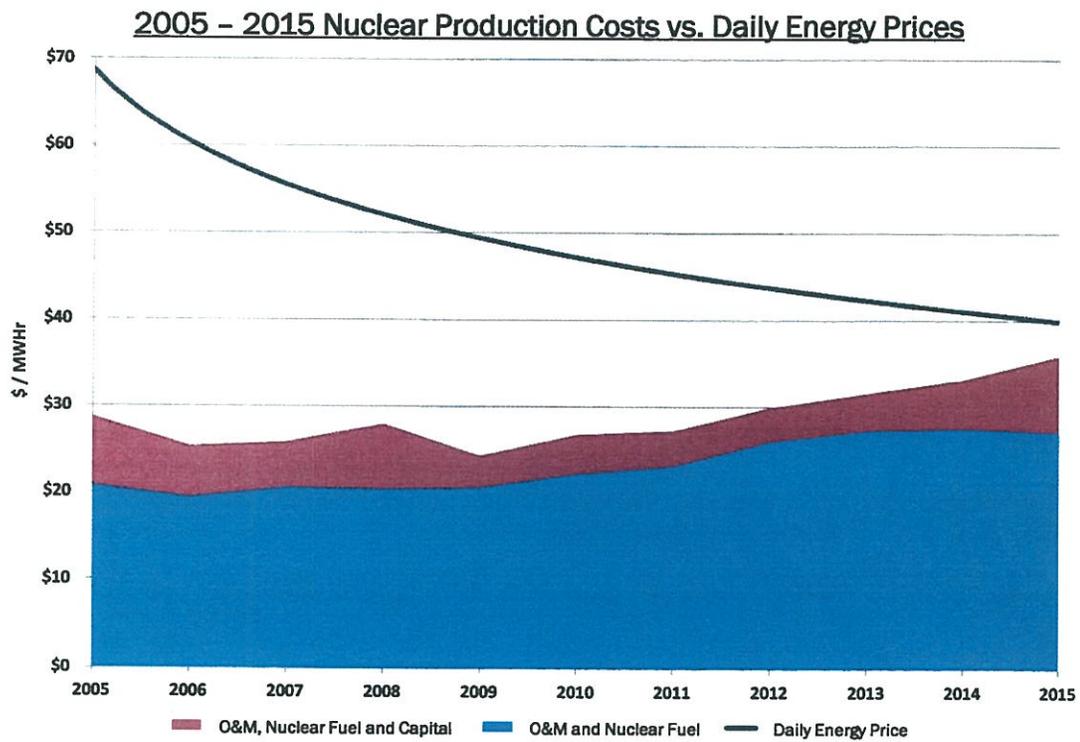
- Spend nearly \$60 million annually in New Jersey for materials and outside services
- Over \$800,000 in charitable contributions in the past two years
- Contribute over \$80 million in taxes annually, including \$30 million in state and local taxes
- Avoid 14 million tons of carbon emissions per year; prevent 26,000 tons of SO₂ and 11,400 tons of NO_x per year at savings of over \$100M

Shale gas has caused substantially lower electricity prices



Actual prices are Day-ahead average around-the-clock prices for PJM West Hub and PSEG Zone; Forecasts are Forward prices as of June 28, 2016

Nuclear power: lower revenues and increased production costs



Daily Energy Price is the around-the-clock price observed at the Hope Creek generating station

Consequences of early retirement of NJ's nuclear power plants

- **Early retirement of NJ's nuclear plants will result in:**
 - Loss of economic benefits
 - Increased cost of power
 - Increased emissions and inability to meet clean air standards
 - An increase in 14 million tons of carbon emissions, 26,000 tons of SO₂ and 11,400 tons of NO_x per year at a cost of over \$100M
 - Increased reliance on natural gas, reducing fuel diversity and resiliency of New Jersey's power supply
 - Long-term fuel deliverability disruptions attributable to weather-related emergencies, e.g., polar vortex, Superstorm Sandy, long-term Interstate pipeline disruptions
- **Avoiding these consequences requires leadership and prudent planning and must take into consideration the inherent delays of building alternatives including**
 - Public opposition to gas pipeline expansion required to meet increased deliverability needs;
 - Potential limitation of fracking under Democratic leadership (due to, e.g., concerns about increased seismic activity and/or public opposition)

...increased costs, increased emissions and greater reliance on natural gas

What are other states doing?

| State | State mechanisms to support existing nuclear generation facilities | Status |
|-------|---|--|
| IL | Legislation to adopt zero emission standard for at-risk nuclear units | Legislation approved and signed into law December 2016 |
| NY | Entered into a cost of service agreement with Ginna nuclear plant to maintain reliability | Agreement in place through 03/2017 and then eligible for ZECs |
| NY | NYPSC adopted a Zero Emissions Credit (ZEC) mechanism to compensate eligible nuclear facilities. Mechanism approved on a plant by plant basis for 12 year duration (six 2-year tranches). Design/duration may be modified or eliminated if other solution available to retain eligible nuclear plants. | Approved by NY Public Service Commission on 08/02/2016 |
| CT | 2016 Senate passed legislation: (1) adding nuclear into definition of a "clean energy" resource making it eligible for long-term contract; and (2) adding 1,100 MWs of clean energy demand to clean energy program. Initial effort stalled in the House, but focus now is on a renewed effort to submit legislation for action in 2017. | Introducing legislation expected as early as 02/2017 |
| OH | Regulatory action to provide financial support to units through a non-bypassable charge to customers also considering re-regulation | PPA effort failed; FE utility received financial support, but not for nuclear unit |
| IA | Regulatory agency approved power purchase agreement between NextEra and local utility for output of Duane Arnold Energy Nuclear Plant | Agreement in place |
| PA | Bipartisan legislative discussions in early stages | TBD |
| TX | Public discussions starting evaluating the risks of nuclear plants closures in the State | TBD |
| VT | No action by State to retain nuclear plant. Vermont Yankee nuclear plant closed 2014 | N/A |
| MA | No action by State to retain nuclear plant. Pilgrim nuclear plant scheduled to close 2019 | N/A |
| WI | No action by State to retain nuclear plant. Kewaunee nuclear plant closed 2013 | N/A |
| NE | No action by State to retain nuclear plant. Fort Calhoun nuclear plant scheduled to close 2016 | N/A |



PSEG

We make things work for you.

ATTACHMENT B

2013 Presentation to Analysts
MARCH 1, 2013

EXCERPT



PSDC

We make things work for you.

We have the **energy** to make things better ... for you, for our investors and for our stakeholders.

2013 Conference Agenda

| Presentation | Presenter |
|------------------------------|------------------|
| Welcome and Introductions | Kathleen Lally |
| PSEG | Ralph Izzo |
| PSE&G | Ralph LaRossa |
| PSEG Energy Holdings | Randall Mehrberg |
| <i>Q&A Session</i> | |
| <i>Break</i> | |
| PSEG Power | William Levis |
| Power ER&T | Shahid Malik |
| <i>Q&A Session</i> | |
| Financial Review & Outlook | Caroline Dorsa |
| Summary | Ralph Izzo |
| <i>Q&A Session</i> | |
| <i>Conference Conclusion</i> | |

PSEG FINANCIAL REVIEW & OUTLOOK

Caroline Dorsa

EXECUTIVE VICE PRESIDENT AND
CHIEF FINANCIAL OFFICER



PSEG

We make things work for you.



Caroline Dorsa

EXECUTIVE VICE PRESIDENT AND CHIEF FINANCIAL OFFICER, EXECUTIVE VICE PRESIDENT AND CHIEF FINANCIAL OFFICER, PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED, PUBLIC SERVICE ELECTRIC AND GAS COMPANY, PSEG POWER LLC AND PSEG SERVICES CORPORATION

Caroline Dorsa was named executive vice president and chief financial officer for Public Service Enterprise Group Incorporated (PSEG) in April 2009. She is also the executive vice president and chief financial officer of Public Service Electric and Gas Company (PSE&G), PSEG Power and PSEG Services Corporation.

Ms. Dorsa is responsible for all financial functions, including Internal Audit Services and Investor Relations. Given the array of financial instruments which serve as the primary means of selling wholesale energy to customers, Ms. Dorsa also has responsibility for the Risk Management function, which provides independent oversight of the PSEG Power trading organization. In addition to her financial responsibilities, Ms. Dorsa leads the Information Technology and Procurement organizations. She is a member of PSEG's Executive Officer Group.

In her role as chief financial officer, she has overseen the execution of the Company's financial strategy, which has involved a significant deleveraging of the balance sheet and enhancement of the company's financial strength. The company is in the midst of a major capital investment program focused on deploying more than \$6 billion over three years to ensure the reliability and efficiency of the energy generation and distribution system in New Jersey. PSEG has an uninterrupted record of paying dividends to shareholders for 105 years.

Ms. Dorsa had been a member of the PSEG Board of Directors for six years, and a member of PSEG's Audit, Corporate Governance and Finance Committees before joining the company's management. Her previous management position had been with Merck & Co., where she was senior vice president – global human health, strategy and integration. Prior to this, Ms. Dorsa served as senior vice president and chief financial officer at Avaya, Inc. Earlier in her career, she held a range of financial positions at Merck, including serving as vice president and treasurer of the company for over 12 years. She was also the Secretary of the Finance Committee of Merck's Board of Directors.

Before joining Merck, Ms. Dorsa worked for Mayor Edward Koch of the City of New York promoting economic development in midtown Manhattan.

Ms. Dorsa is a member of the Junior Achievement of New Jersey State Board of Directors. She is a member of the Board of Directors and the financial expert for the Finance and Audit Committee of Biogen Idec (NASDAQ: BIIB), a biopharmaceutical company located in Cambridge, MA. Ms. Dorsa is also a member of the Board of Directors and Chairman of the Audit Committee of Joule, a privately financed solar fuels company based in Bedford, MA.

Ms. Dorsa holds a B.A. from Colgate University and an M.B.A from Columbia Business School.



PSEG

Strong financial position to support our business initiatives

Financial Position

- ✓ Achieved Earnings Guidance
- ✓ Stable Dividend and Opportunity for Growth
- ✓ Strong Balance Sheet
- ✓ Regulated Growth Opportunity without Equity Issuance
- ✓ Solid Credit Ratings
- ✓ O&M Controlled
- ✓ Well Funded Pension

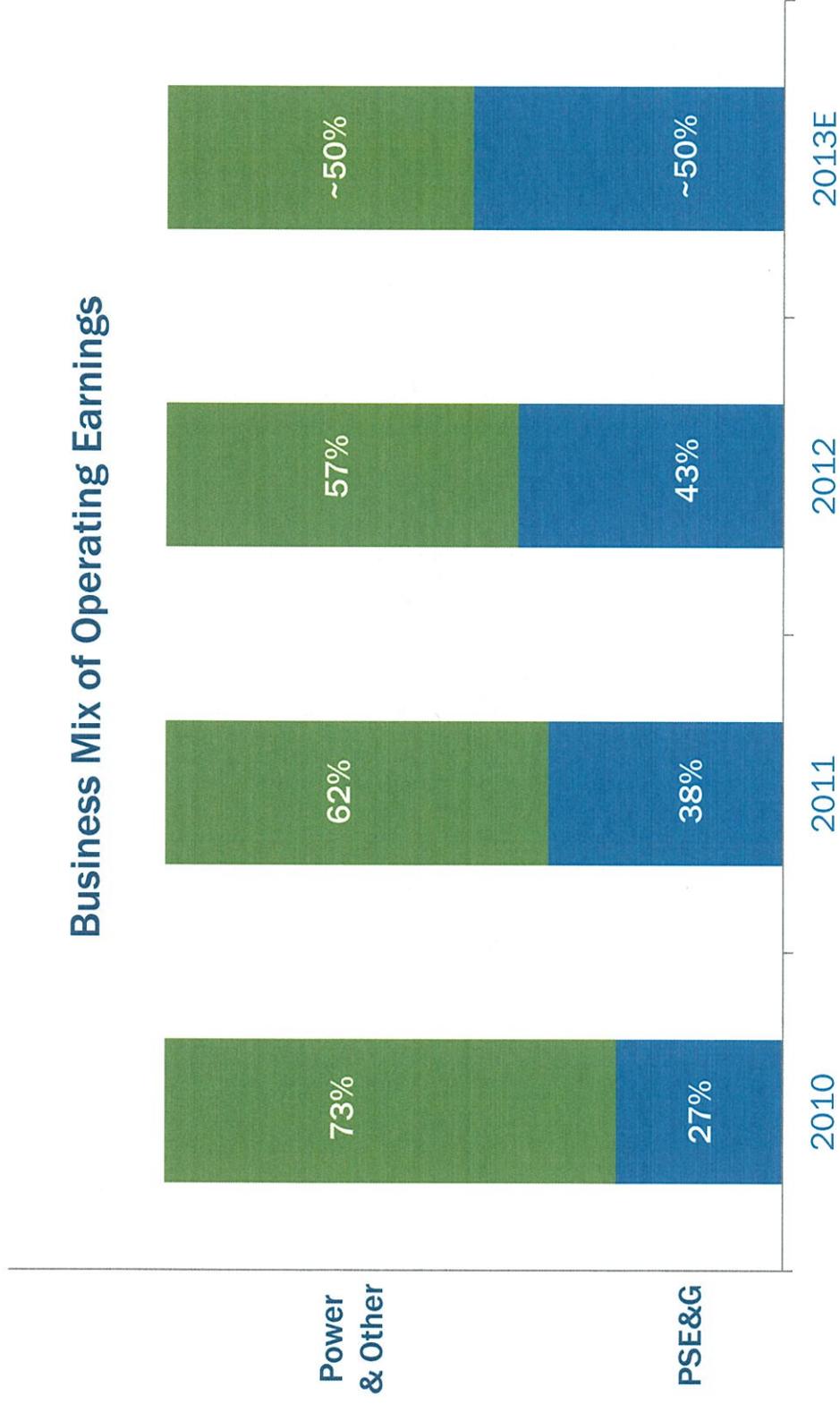
2013 guidance in same range as 2012

| PSEG Operating Earnings | |
|-------------------------------|------------------------|
| \$ Millions (except EPS) | 2013E |
| PSEG Power | \$535 - \$600 |
| PSE&G | \$580 - \$635 |
| PSEG Energy Holdings/Parent | \$25 - \$35 |
| Operating Earnings* | \$1,140 - \$1,270 |
| 2013 Earnings Guidance | \$2.25 - \$2.50 |



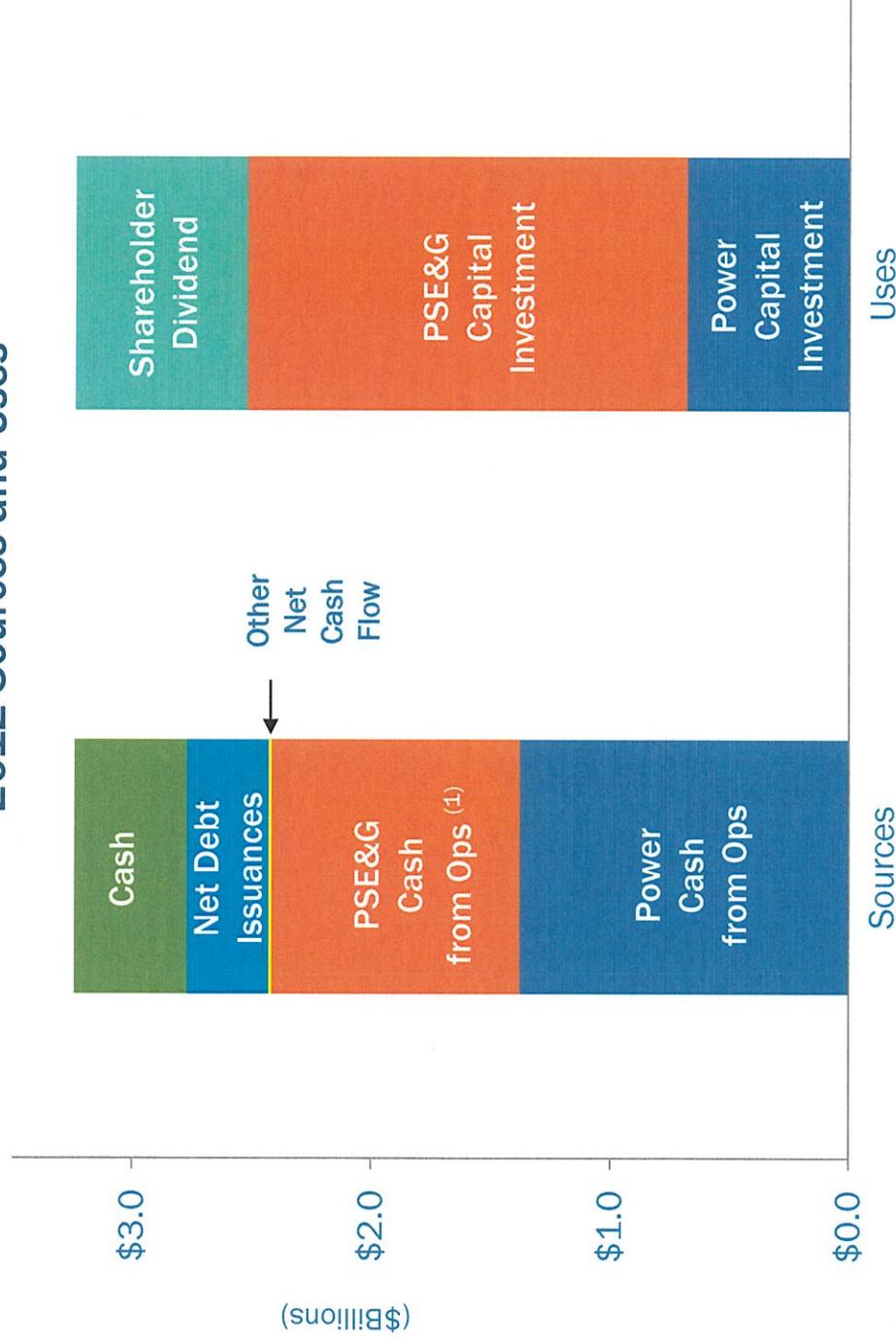
*SEE SLIDE A FOR ITEMS EXCLUDED FROM INCOME FROM CONTINUING OPERATIONS TO RECONCILE TO OPERATING EARNINGS.
E = ESTIMATE

PSE&G is expected to represent 50% of 2013 operating earnings



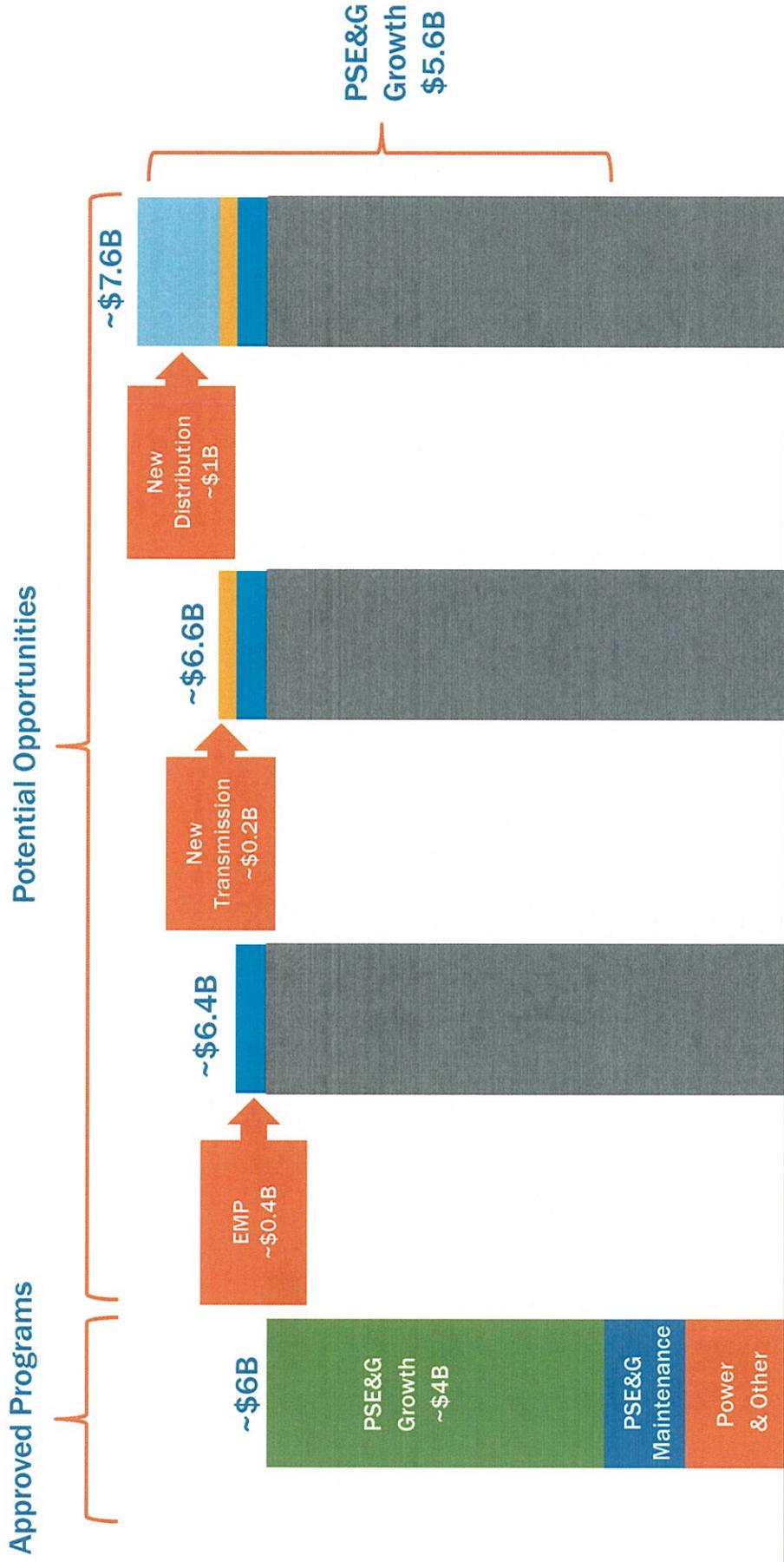
In 2012, PSE&G executed its capital program, Power generated significant free cash flow and PSEG increased its shareholder dividend

2012 Sources and Uses



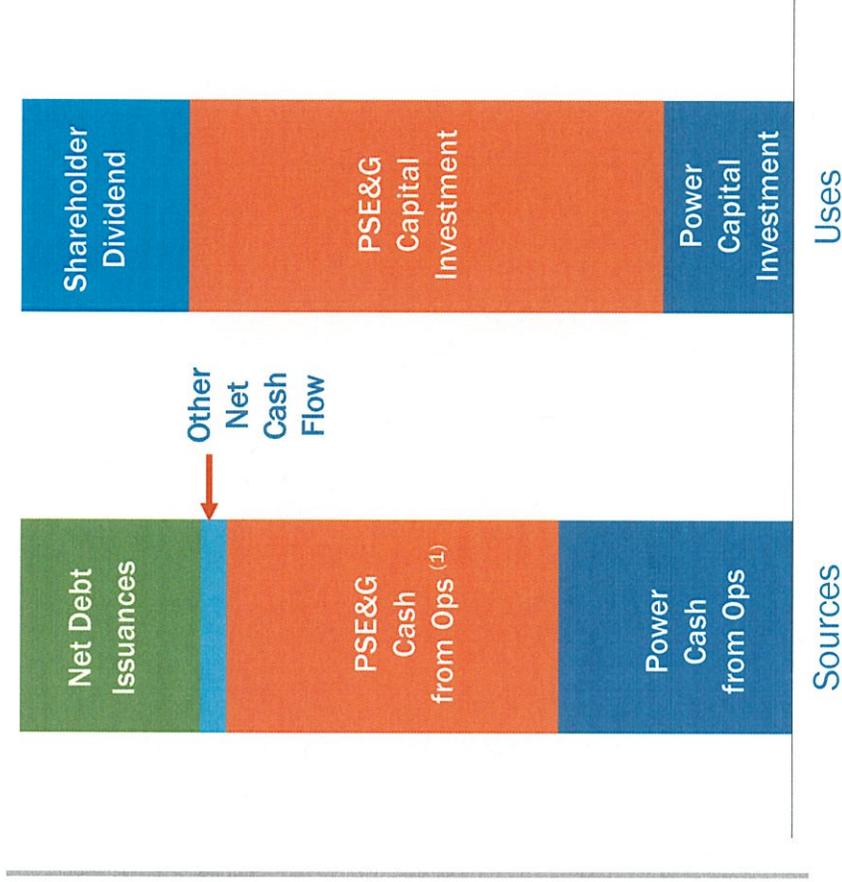
Our capital investment options can result in as much as \$5.6B of utility growth investment through 2015

2013 – 2015E Capital Investment Potential Opportunities

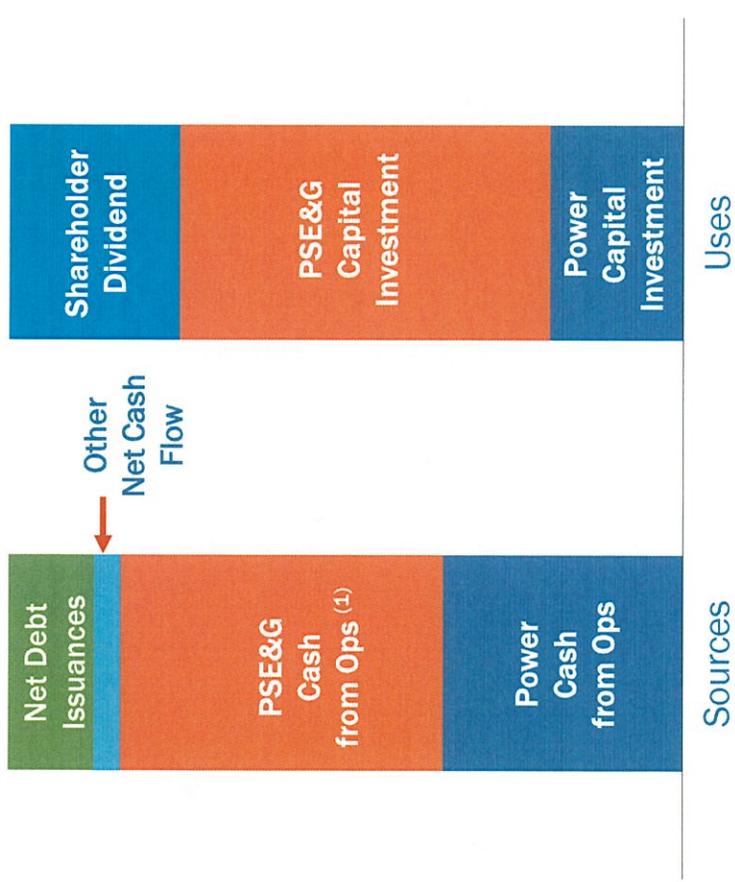


All scenarios can be financed without new equity

Approved Programs plus EMP, New Transmission and New Distribution



Approved Programs

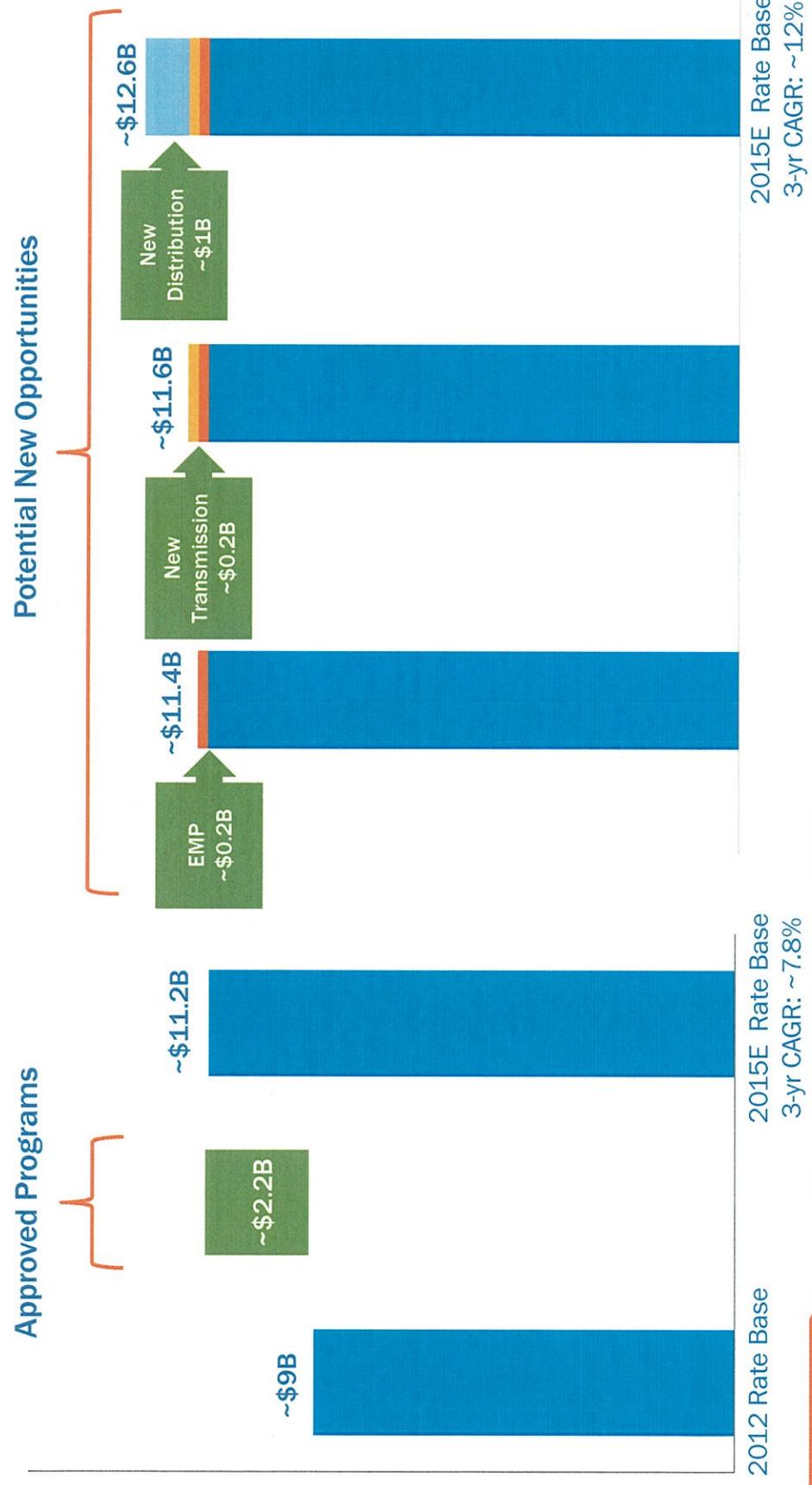


(1) PSE&G CASH FROM OPERATIONS ADJUSTS FOR SECURITIZATION PRINCIPAL REPAYMENTS OF ~\$725M FROM 2013-2015

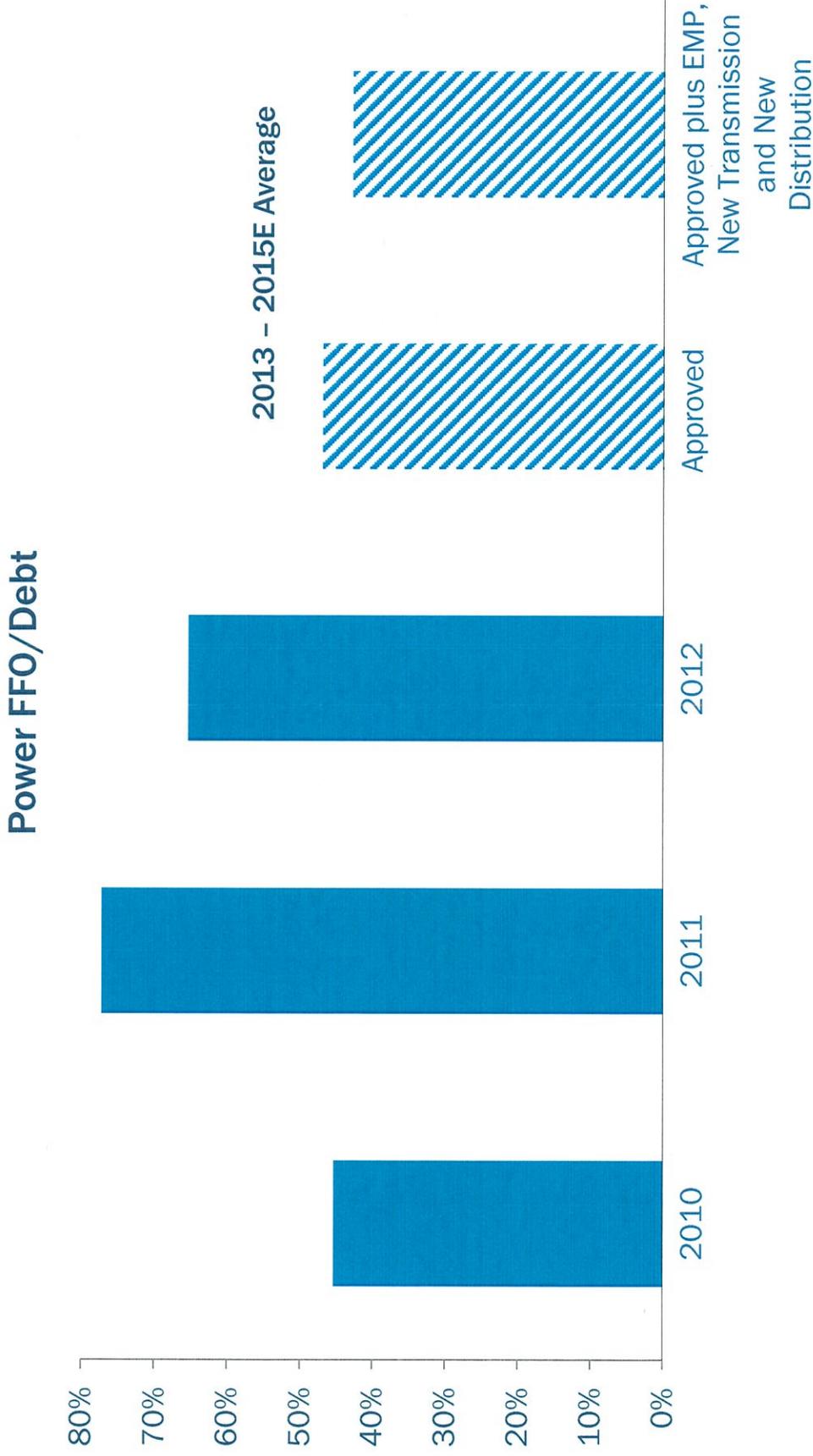
E = ESTIMATE

PSE&G's capital spending drives regulated earnings growth with a potential future rate base of up to ~\$12.6B

2013 - 2015E Rate Base Growth



Power's credit metrics are expected to remain strong

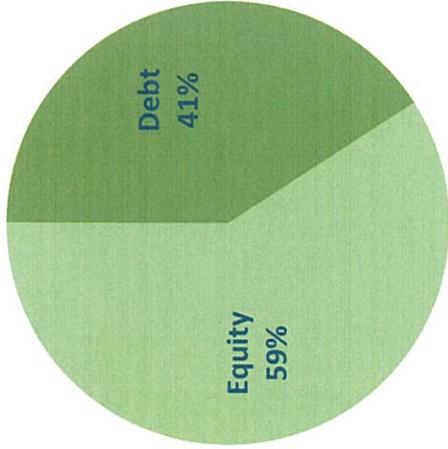


Using PSEG's balance sheet strength

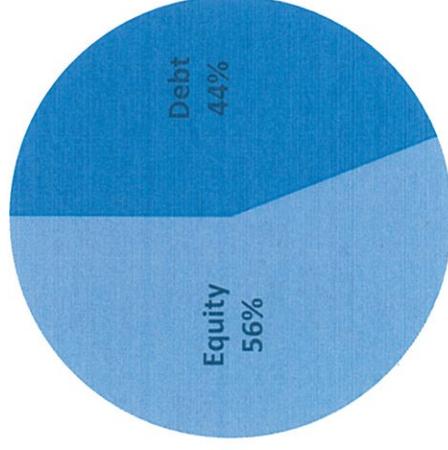
to finance growth in the regulated enterprise without equity issuance

PSEG Total Capitalization

2012



2015E*



PSEG

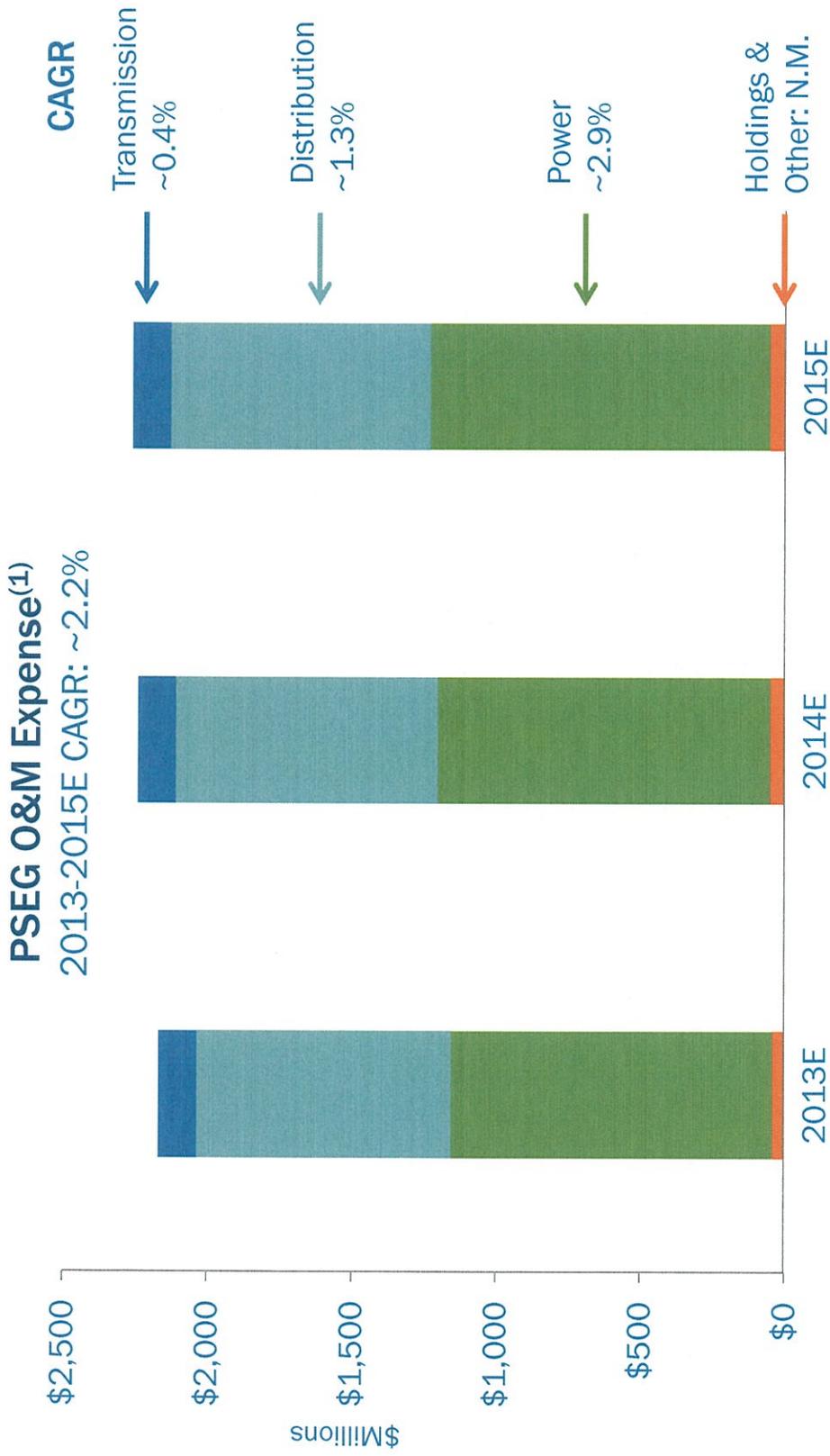
* E = ESTIMATE; INCLUDES THE FOLLOWING PROPOSED FILINGS: EE4A, SL3, S4AE, ENERGY STRONG (ES) AND TRANSMISSION HARDENING.

Our investment programs are affordable, helped by the expiration of known charges by 2017, which lower the average residential customer bill by ~ 8.7% based on today's current bill

| PSE&G Securitization & NUG Impacts (\$Millions) | | | | | | |
|---|-----------------------|--------------|-------------------------------|--------------|----------|--|
| PSE&G Securitization Impacts | 2013 | 2014 | 2015 | 2016 | 2017 | |
| Revenues | 439 | 445 | 386 | 0 | 0 | |
| Interest Expense | (46) | (30) | (11) | 0 | 0 | |
| Amortization | (253) | (273) | (233) | 0 | 0 | |
| Deferred Tax & Other | (140) | (142) | (142) | 0 | 0 | |
| P&L Impact (GAAP view) | 0 | 0 | 0 | 0 | 0 | |
| PSE&G Non-Utility Generation | 2013 | 2014 | 2015 | 2016 | 2017 | |
| Revenues* | 157 | 167 | 141 | 49 | 0 | |
| Expenses | (157) | (167) | (141) | (49) | 0 | |
| P&L Impact (GAAP view) | 0 | 0 | 0 | 0 | 0 | |
| <small>*NUG revenues reflect Feb 1, 2013 rates</small> | | | | | | |
| Typical Current Average Residential Customer Bill Impact | Securitization | ~6.6% | Non-Utility Generation | ~2.1% | | |

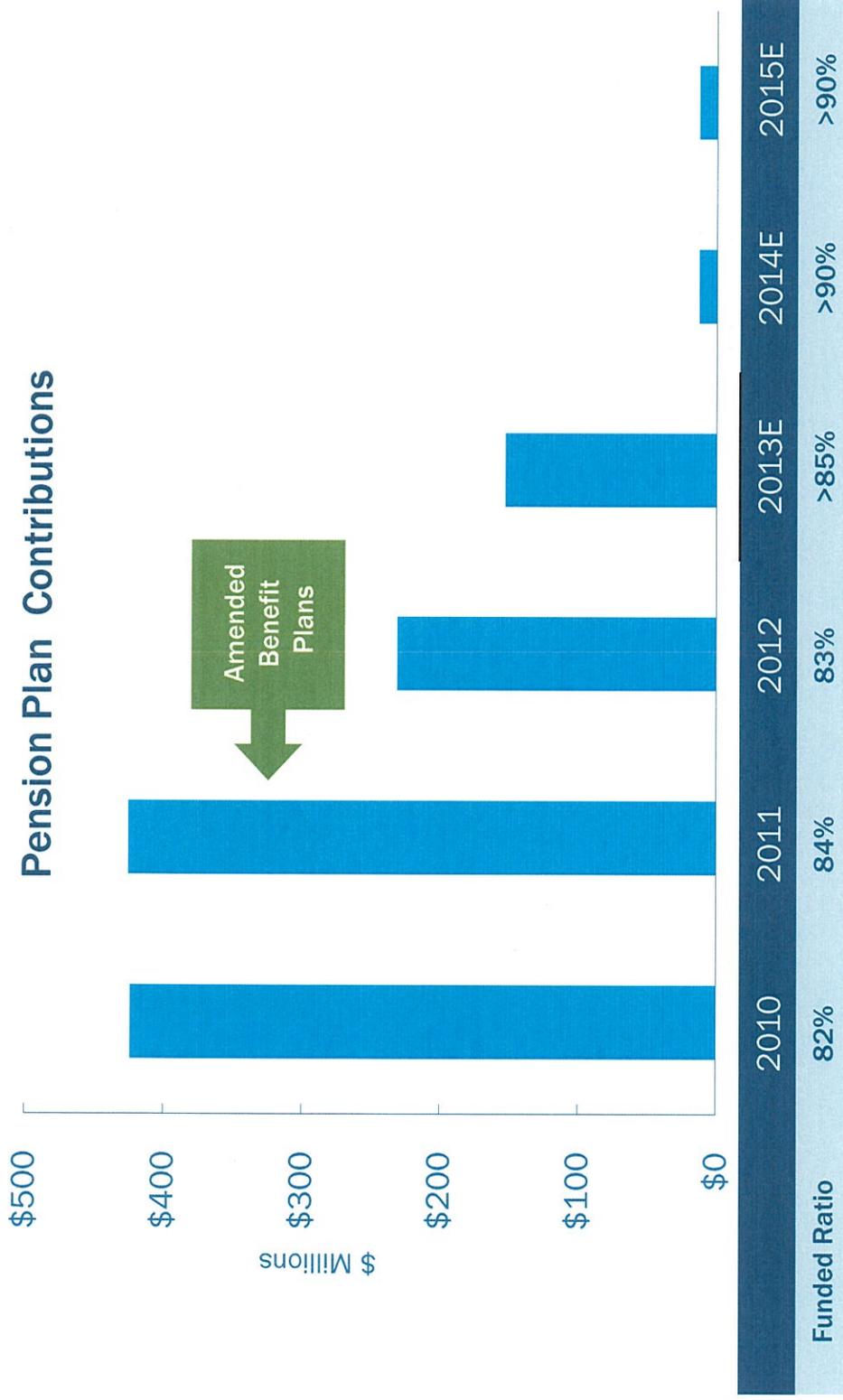


Modest O&M growth with Power increases from CCGT maintenance cycles, due to high utilization rates



(1) POWER EXCLUDES IMPACTS FROM STORM RECOVERY COSTS AND POTENTIAL RELATED INSURANCE PROCEEDS NM = NOT MATERIAL. E = ESTIMATE.

Pension contributions expected to decline with well funded plan



PSEG's long-term outlook is influenced by Power's hedge position and increased investment at PSE&G



Segment EPS Drivers

2014E 2015E

| | | |
|--|-----------------|-----------------|
| Each \$1/mcf Change in Natural Gas Each \$2/MWh Change in Spark Spread Each \$2/MWh Change in Dark Spread Each 1% Change in Nuclear Capacity Factor | \$0.03 - \$0.06 | \$0.10 - \$0.13 |
| | \$0.04 | \$0.04 |
| | \$0.01 | \$0.01 |
| | \$0.01 | \$0.01 |

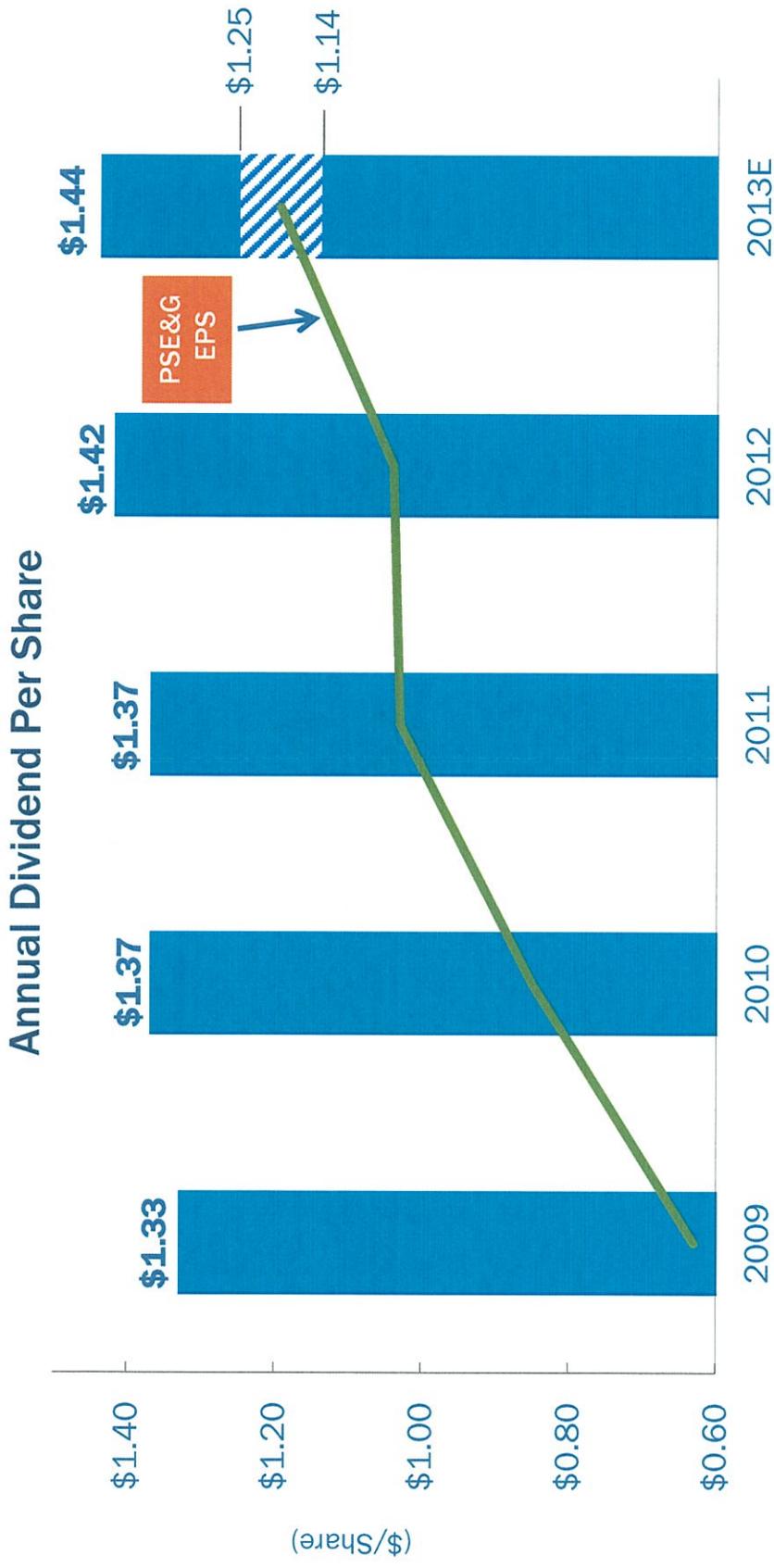


| | | |
|---|--------|--------|
| Each \$100 Million of Incremental Investment Each 1% Change in Sales Electric Gas Each 1% Change in O&M Each 10 bp Change in ROE | \$0.01 | \$0.01 |
| | \$0.01 | \$0.01 |
| | \$0.01 | \$0.01 |
| | \$0.01 | \$0.01 |



Opportunity for modest and sustainable

dividend increases consistent with stable regulated growth and cash generation outlook at PSEG Power



Summary

- Operating Earnings Guidance for 2013 of \$2.25 - \$2.50 per share with earnings mix shifting to 50% regulated
- Double digit operating earnings growth at PSE&G starting in 2013, and continuing through 2015 driven by transmission investments and approved programs
- Power's continued focus on operational excellence, market expertise and financial strength reduces risk in low price environment
- Strong Balance Sheet and Cash Flow support full capital program without the need for equity
- Long history of returning cash to the shareholder through the common dividend, with opportunity for further growth



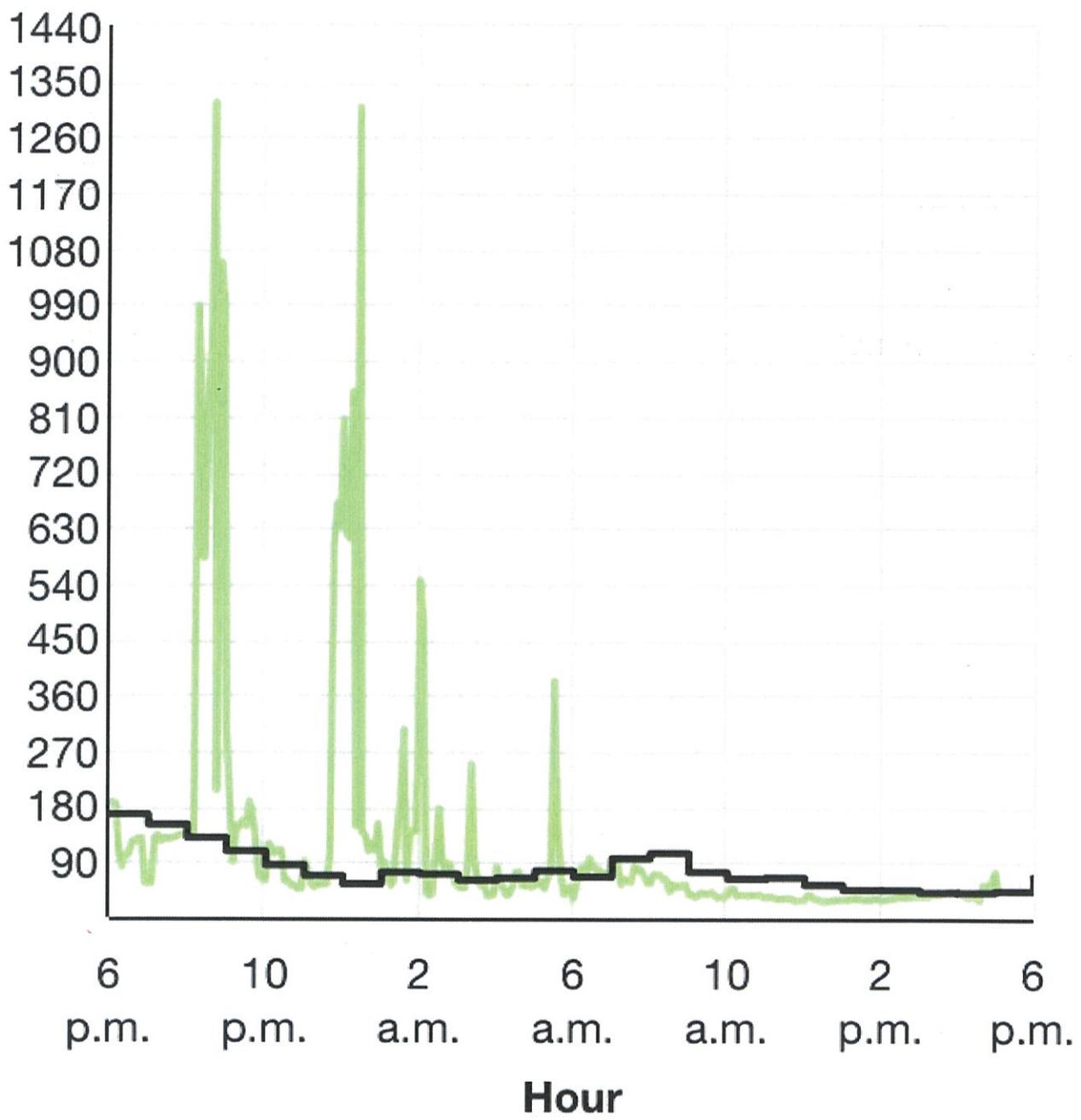
ATTACHMENT C

As of January 22, 2019 5:05 PM EPT

AE

\$/MW

Current LMP: \$44.59



Actual Day-Ahead

Close Trend