STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE APPLICATION OF PSEG NUCLEAR LLC FOR THE ZERO EMISSION CERTIFICATE PROGRAM – HOPE CREEK

IN THE MATTER OF THE APPLICATION OF PSEG NUCLEAR LLC AND EXELON GENERATION COMPANY, LLC FOR THE ZERO EMISSION CERTIFICATE PROGRAM – SALEM UNIT 1

IN THE MATTER OF THE APPLICATION OF PSEG NUCLEAR LLC AND EXELON GENERATION COMPANY, LLC FOR THE ZERO EMISSION CERTIFICATE PROGRAM – SALEM UNIT 2

BPU Docket Nos. ER20080559, ER20080557 and ER20080558

DIRECT TESTIMONY
OF
DANIEL CREGG
EXECUTIVE VICE PRESIDENT AND
CHIEF FINANCIAL OFFICER OF PSEG

January 29, 2021

CONTENTS

I. INTRODUCTION

A. Witness Identification

Q. What is your name?

A. My name is Daniel J. Cregg.

Q. By whom and in what position are you employed?

A. I am the Executive Vice President and Chief Financial Officer for Public Service Enterprise Group and its subsidiaries, including PSEG Power and PSEG Nuclear LLC. PSEG Nuclear LLC ("PSEG") is the owner and operator of the Hope Creek plant, and the co-owner[1] and operator of the Salem I and Salem II plants.

B. Background and Qualifications

Q. Please describe your employment experience and educational background.

A. I hold a B.S. in Accounting from Lehigh University and an MBA from the Wharton School of the University of Pennsylvania, and I am a Certified Public Accountant. I have been employed by Public Service Enterprise Group ("Enterprise") since 1991, and have held many roles prior to being named to my current role of Chief Financial Officer in 2015, including a decade leading the financial functions for Enterprise's two major subsidiaries in my roles as VP Finance for PSEG Power and VP Finance for PSE&G, providing both regulatory and competitive market expertise. I currently serve on the board of the Community Food Bank of New Jersey, and prior to joining Enterprise, I worked for five years with Deloitte, primarily in the utility sector in various capacities.

---

[1] PSEG has been vested with the sole and exclusive authority to make retirement decisions for the plants, covering Exelon Generation's 42.59% minority ownership share as well as PSEG's 57.41% majority ownership share. The Salem I and II submittals address all elements of the applications for 100% of the ownership interest and are submitted on behalf of both owners.

C. Purposes of Testimony

Q. What are the purposes of your testimony?

A. I discuss the projected revenues, costs, costs of risks, and overall financial need of the three PSEG Power nuclear generating stations – Hope Creek, Salem I, and Salem II. My testimony first addresses projected revenues and responds to Levitan's discussion concerning how projected revenues were calculated. Next, I provide an overview of the costs associated with the three-year period that begins with the 2022/2023 energy year and extends to the close of the 2024/2025 energy year ("the ZEC2 period"). I explain how the costs included in PSEG's applications fit into the categories outlined in the Zero Emissions Credits ("ZEC") Act. Then, I explain how PSEG calculated the costs of operational and market risks associated with that three-year period, and why it is both legally required and reasonable to include costs of risks in the analysis of PSEG's need for ZECs. I conclude by setting forth the plants' overall financial need.

Q. What, in sum, are your conclusions?

A. PSEG's total costs and risks exceed its projected revenues in each of the energy years 2022/2023 through 2024/2025. PSEG's total needs, updated from its initial applications to reflect forward prices and the cost of market risks as of September 30, 2020, and all other costs as of October 31, 2020, are set forth in the table below, on a plant-by-plant basis: **[BEGIN CONFIDENTIAL]**

[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

II. PSEG'S PROJECTED REVENUES

Q. Has PSEG's need for ZECs grown since the last ZEC application period?

A. Yes.

Q. Why is that?

A. PSEG's need for ZECs has grown largely because forward energy prices have fallen below the levels that were projected during the last ZEC application period. Remember that PSEG's projected shortfall is equal to our projected costs and risks less our projected revenues. In comparison to the three energy years 2019/2020 through 2021/2022 ("the ZEC1 period") costs in the ZEC2 period have increased slightly, **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** while expected revenues have declined due to the decline in forward energy prices.

The table below shows the change in realized energy revenues, on a $/MWh basis. The realized energy revenue rate is down **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the three-year ZEC2 period as compared to the three-year ZEC1 period.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Explain PSEG's methodology for calculating projected revenues.

A. Total revenue is the sum of energy, capacity, and ancillary services revenue.

First, PSEG calculated the expected energy revenues for each plant. Expected energy revenue is the product of the expected PJM locational marginal prices ("LMP") at the unit's location and the unit's expected output. PSEG estimated each unit's expected output, taking into account historical unplanned outage rates and forecasted refueling outages. To calculate the LMP, PSEG takes into account the forward price for zonal LMPs and adjusts that forward price to take into account transmission congestion and marginal losses between the forward PECO Hub price and the generating unit.

Second, PSEG calculated the expected capacity revenues for each plant. Expected capacity revenue is the product of the quantity of unforced capacity the unit is eligible to sell into the auction, and the forecasted auction price.

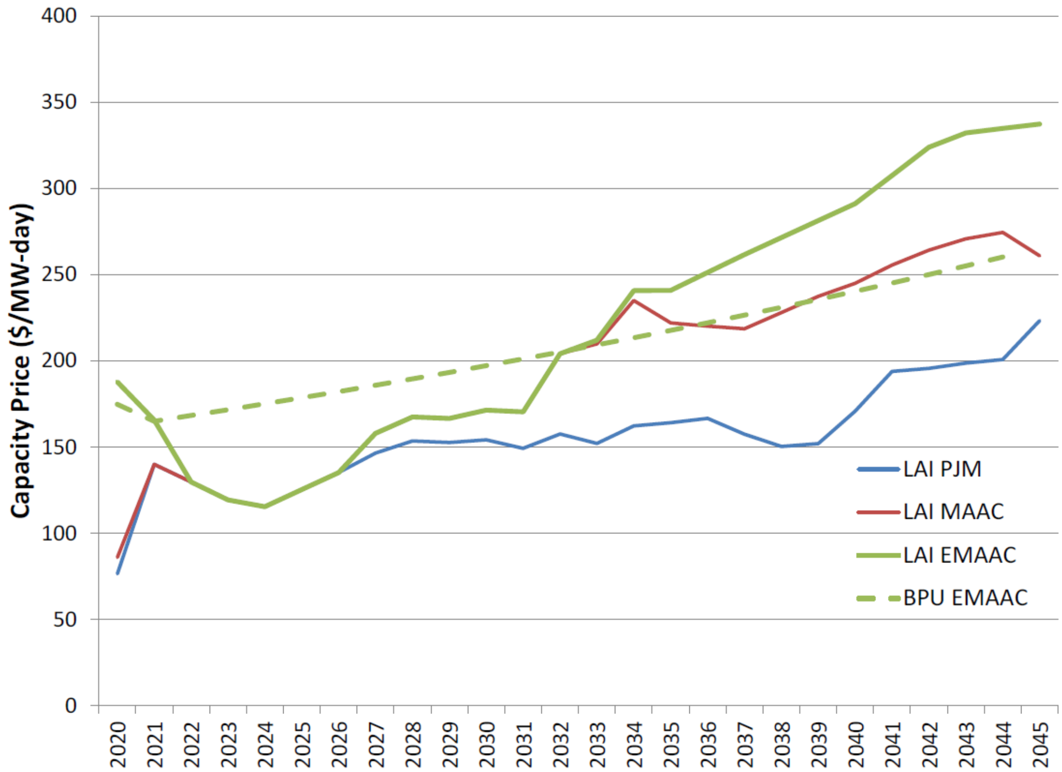
Third, PSEG calculated the expected revenue each plant will receive for providing reactive power voltage support ancillary services. These revenues are based on tariff rates.

Q. With regard to projected capacity revenues, the Levitan Reports note that the Board recently completed an offshore wind solicitation that assumes a capacity price, and suggests that capacity price should be used to calculate PSEG's capacity revenues. *See, e.g.,* Salem I Report at 15. Is that an appropriate methodology?

A. No, not in this instance. In the offshore wind proceeding, the Board was addressing the long-term capacity outlook to evaluate an award across twenty years. The analysis simply escalated recent historical pricing for inflation, and carried that price escalation out over twenty years. This proceeding addresses a relatively short time span of three years, and there is more information available to support a more detailed fundamental forecast. In the offshore wind proceeding, Levitan concluded that across the twenty-year horizon, the Board's approach reached the same approximate value that Levitan derived using its modeling. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The chart below depicts the forecasted capacity prices calculated by the Board and by Levitan in the offshore wind proceeding, and Levitan's analysis shows Levitan's capacity price estimates ranging lower than or near $130 per MW-day in the 2022-2025 timeframe that is relevant in this ZEC proceeding.[2]

[2] *See Evaluation of New Jersey Solicitation for ORECs for Offshore Wind Capacity*, Levitan & Associates, June 21, 2019.

Figure 6. BPU and LAI Capacity Price Forecasts



Q. **The Levitan Reports imply that an average of historical capacity prices might be more appropriate than PSEG's forecasting methodology. Is averaging historical data an appropriate methodology?**

A. Not in this case. In the absence of forward-looking data, it may be reasonable to use historical data as a basis to predict future prices. However, the next capacity auction will incorporate several known material changes, including transmission upgrades and changes that were predetermined through the quadrennial review conducted by PJM in 2019, which ultimately resulted in a lower capacity demand curve and, as a result, a lower expected capacity price. *See* Confidential Exhibit A. PSEG's methodology incorporates those known changes, as well as the fundamentals of the markets, and all variables known at the time. An average of historical results would ignore these known changes.

Q. The Independent Market Monitor ("IMM") has also taken positions regarding forecasted prices. In the last ZEC proceeding, the IMM argued that energy prices might well increase because of policy changes. Did that bear out?

A. The IMM did hypothesize that energy prices might increase. However, in reality energy prices fell over the last three years.

Q. What effect will changes to the Operating Reserve Demand Curve ("ORDC") and fast-start pricing, which have been approved by FERC, have on energy prices?

A. Those changes are known to the market, and as such it is reasonable to assume they would be reflected in forward prices.

III. PSEG'S COSTS OTHER THAN RISKS

Q. Explain the methodology PSEG used to determine its costs to continue operating the Hope Creek and Salem plants.

A. The ZEC Act provides applicants with two potential approaches to meet the financial criterion: to demonstrate that the plant is "projected to not fully cover its costs and risks, or alternatively is projected to not cover its costs including its risk-adjusted cost of capital." N.J.S.A. 48:3-87.5(e)(3) (emphasis added). The ZEC Act allows the applicant to choose between these two methods, and PSEG has selected the first.

Q. At a high level, please explain the categories of costs – other than risks – included in PSEG's applications.

A. As prescribed by the ZEC Act, applicants should include the following types of expenses: (i) operation and maintenance expenses, (ii) fuel expenses, including spent fuel expenses, (iii) non-fuel capital expenses, and (iv) fully allocated overhead costs. N.J.S.A. 48:3-87.5(a).

PSEG's costs include the following types of operation and maintenance expenses: (i) labor costs, including overtime and fringe benefits associated with plant operations and outages; (ii) support services and allocated overhead, including administrative and general expense, insurance cost, and other corporate overhead costs; (iii) outside services costs, such as maintenance support and other contractors; (iv) real estate taxes; and (v) other costs, including regulatory fees, membership fees, facilities and rental costs, office expenses, and business travel.

PSEG's costs also include fuel expenses, spent fuel costs, and non-fuel capital expenditures associated with long-lived plant equipment required to maintain safe and reliable operations. In addition, PSEG's costs include the cost of working capital, which is the interest expense related to the amount of capital required to finance items such as materials and supplies inventory, long positions in nuclear fuel, and revenue receivables from the sale of electricity and capacity, offset by accrued expenses and payables necessary to operate the units. Working capital costs also include the cost related to collateral or margin payments related to hedging activity.

Q. The Levitan Reports question whether spent fuel charges "are true costs if PSEG is neither incurring nor accruing these costs." ***See, e.g.*****, Salem II Report at 18. Why does PSEG consider spent fuel charges among its costs?**

A. The ZEC Act directs applicants to submit financial information including "spent fuel expenses." N.J.S.A. 48:3-87.5(a). PSEG is not currently paying spent fuel charges to the DOE, but remains obligated under federal law to pay for the removal of spent fuel from the Salem and Hope Creek facilities. The obligation to pay DOE for spent fuel disposal was suspended by court order because DOE was not developing the long-term federal repository to dispose of the fuel. But DOE has a continuing legal obligation to do so, and, when it begins to fulfill this legal responsibility, the source of funding will be the plants. In the meantime, we continue to build up spent fuel inventory for each MWh produced, and because we bear the financial obligation of spent fuel disposal, we continue to build up costs related to disposal. It is prudent to assume that DOE will perform its legal obligation, and we will incur those costs. Moreover, those costs are avoidable if the plants retire. If PSEG ceases operation, the units would not be generating any additional spent fuel. As a result, this additional spent fuel disposal cost would be avoided.

IV. RISKS

A. Overview

Q. Can you please explain conceptually why risk is an important consideration in decision-making regarding retirement of the nuclear plants?

A. Companies must think about risk when making business decisions. While we can try to forecast our expected costs and expected revenues, reality does not always go according to plan. A decision-making process that does not incorporate risk considerations is incomplete. Consider a hypothetical business endeavor with the potential for high revenues at low cost. If those two factors were the only factors considered, one would engage in the business. But if there is a significant risk that the projected revenues will not actually materialize, or that the costs will be significantly higher than projected, one's evaluation of the business may change. For example, a rational decision-maker might forgo investing in a business with high expected return potential but significant risks (for example, subprime loans), in favor of other investment opportunities that have lower return potential but are lower risk (for example, highly rated corporate debt).

These considerations apply equally when the business decision to be made is whether to continue operating a nuclear generating plant. PSEG must decide whether to continue operating its Hope Creek, Salem I, and Salem II nuclear units. Like all other business decisions, that decision involves not only an assessment of projected revenues and costs, but also the degree of risk – that is, the degree to which one's projections will be wrong and, in particular, the potential that the business could experience very significant losses.

The ZEC Act instructs applicants to include “operational risks,” which include “the risk that operating costs will be higher than anticipated,” and “market risks” which include the “risk of forced outages and the associated costs arising from contractual obligations, and the risk that output from the nuclear plant may not be able to be sold at projected levels.” N.J.S.A. 48:3-87.5(a). This language indicates that the Legislature understood that operational and market risks are critical in making the business planning decision whether to cease operations. Based on this explicit instruction in the statute, as well as the practical reality of how business planning decisions are made, the Board cannot exclude risk from the analysis—as the Board recognized in the last ZEC proceeding.

Q. Risk is not a component of traditional public utility ratemaking. Can you explain why risk is an appropriate consideration in the context of ZECs?

A. In traditional public utility ratemaking, the risks associated with the utility’s business are captured in the cost of capital. Utility rates include a cost of capital component in recognition of the fact that no investor would choose to invest in a business if the anticipated outcome is for revenues to solely cover the costs of operating the business. The cost of capital included in utility rates is generally intended to allow the utility to provide its investors a rate of return that is commensurate with the risk of investing in the utility, as perceived by the investing public (*i.e.*, the market).

The ZEC Act provides that a nuclear power plant may demonstrate to the Board that the plant “is projected to not fully cover its costs and risks, or alternatively is projected to not cover its costs including its risk-adjusted cost of capital.” N.J.S.A. 48:3-87.5(e)(3). Thus, under either alternative, the Act contemplates incorporating amounts in excess of the costs of operations. The Act allows the applicant to calculate that excess by showing either (i) that its revenues will not fully cover its "costs and risks," or (ii) that the revenues will not cover the more traditional ratemaking metric of "costs including [the] risk-adjusted cost of capital." Under the first alternative, risks are considered and calculated directly, rather than recovered through an explicit return on capital. Under the second alternative, risks are recovered through the inclusion of a cost of capital.

These two ways of establishing eligibility acknowledge the fact that, although nuclear plants are not traditional public utilities, they still need to attract capital in order to continue as a going concern. The Legislature recognized the need to include more than operating costs in assessing financial need for the simple reason that a prudent business owner would not run a business, particularly one with significant risks, if, in a year in which all went according to plan, the business owner could expect only to cover its budgeted costs. No business is sustainable unless it generates sufficient revenue not only to cover its costs when all goes according to plan, but also to make it worthwhile for the owner to accept the risk of adverse events that could significantly increase costs or reduce revenues.

<u>Operational Risk</u>

Q. The ZEC Act describes two types of risk: operational risk and market risk. What is operational risk?

A. The ZEC Act provides that "operational risks" include, among other things "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." N.J.S.A. 48:3-87.5(a).

Q. Please describe how PSEG has calculated the cost of operational risk.

A. Since operational risk reflects unexpected regulatory developments, equipment failures, and reductions in output, it is impossible to predict the precise costs that will be incurred in connection with operational risk in a given year. To reflect the uncertainty associated with operational risks, PSEG applied a 10% adder to its best estimate of foreseeable future costs. This methodology is consistent with the manner in which PJM determines a facility's costs for energy and capacity bids.[3] FERC has found that the 10% adder "account[s] for uncertainty in the values of the costs utilized in computing … cost-based offers before all costs are known."[4]

Q. The Levitan Reports state that PJM's 10% energy price adder is intended to account for variations in fuel prices experienced by natural gas generators, and so may not support PSEG's 10% adder for operational risks. *See, e.g.*, Salem II Report at 19-20. Do you agree?

A. No. To the contrary, the PJM Tariff expressly applies the 10% adder to the cost-based energy bids of all types of generating plants, including nuclear plants, and is not limited to gas-fired generating plants.[5] The PJM Tariff states, "For offers of $2,000/MWh or less, [the offer cost cap shall be] the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals ('incremental cost'), *plus up to the lesser of 10% of such costs or $100 MWh,* the sum of which shall not exceed $2,000/MWh."[6] In fact, PSEG's fuel cost policy applicable

---

[3] *See* PJM Open Access Transmission Tariff ("PJM Tariff"), Attachment DD, Section 6.8(a) (capacity bids); Attachment K, Appendix., Section 6.4 (energy offer price caps).

[4] *PJM Interconnection, LLC*, 153 FERC 61,289, P 30 (2015).

[5] PJM Tariff, Attachment K-Appendix, Section 6.4.2(a)(ii); PJM Operating Agreement, Schedule 1, Section 6.4.2(a)(ii).

[6] *Id.* (emphasis added).

to the Salem and Hope Creek plants, approved by both PJM and the IMM, expressly provides that the nuclear plants may use the 10% adder for cost-based energy bids.

The Levitan Reports' incorrect assertion that the 10% adder only covers fuel cost risk "specifically [for] gas price" derives from Levitan's reliance on the wrong provisions of the PJM tariff. Salem II Report at 20. Levitan references a determination by FERC and a filing by PJM that are related to Section 6.4.3 of the PJM Tariff, rather than the appropriate provision, Section 6.4.2. *Id.* As described above, Section 6.4.2 deals with the determination of cost-based bids and provides for the 10% adder. In contrast, Section 6.4.3 is inapplicable for two reasons: first, this section performs a completely different function of addressing when clearing prices are set rather than the determination of cost-based bids, which is the function of Section 6.4.2. Second, Section 6.4.3 deals with an extremely rare situation in PJM when bids are between $1,000/MWh and $2,000/MWh. Moreover, Levitan is also wrong because Section 6.4.3 applies the same adder authorized under Section 6.4.2, *in addition to a separate adder* for the fuel cost risk experienced by gas-fired plants.[7] Accordingly, Levitan's claims are simply misplaced and unsupported.[8]

[7] *See* PJM Tariff, Attachment K-Appendix, Section 6.4.3 and the PJM Operating Agreement, Schedule 1, Section 6.4.3 (equation including "Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and A = Cost adder, in accordance with Section 6.4.2(a)(ii) of this Schedule").

[8] In fact, although the purposes of the two provisions are different, the provision governing when bids between $1,000/MWh and $2,000/MWh may set prices still includes the 10% adder as a value in the calculation *plus* an additional 10% adder for fuel cost risk.

Q. The Levitan Reports also state that PJM's 10% capacity price adder is intended to account for the impact of inflation on newly-constructed generators, and so may not apply to the PSEG units. *See, e.g.*, Salem II Report at 20-21. Do you agree?

A. I disagree for two reasons. First, Levitan's statement that PJM's 10% capacity price adder accounts for the impact of inflation on plants under construction is apparently based on a quote from the PJM Tariff. The PJM Tariff, however, does not support that conclusion. In fact, the PJM Tariff states specifically that the "Adjustment Factor equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment … to account for expected inflation." *See* Salem I Report at 20, *citing* PJM Tariff Attachment DD Section 6.8(a) (emphasis added). Thus, PJM applies the 10% adder to account for uncertainties regarding costs, and then applies a separate adder for inflation. This demonstrates that PJM (and FERC, which has approved the PJM Tariff) considers a 10% adder for cost uncertainty to be reasonable.

Second, the Levitan Reports are mistaken in asserting that this adder is applied only to generators that are under construction. *See, e.g.*, Salem II Report at 20. The adder is applied to existing generators as well.[9] The application of the adder to existing generators makes sense, since existing units can also experience uncertainty regarding the cost of capital investments and uncertainty in capital investment planning. These issues are particularly pronounced for nuclear units, as discussed in detail in the testimony of Carl Fricker on behalf of PSEG.

---

[9] PJM Tariff, Attachment DD, Section 6.8 that prescribes the "Adjustment Factor" including the 10% adder, as described in the text infra, is applicable to a "Generation Capacity Resource" and under the PJM Reliability Assurance Agreement a "Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource." Reliability Assurance Agreement, Definitions, p. 11.

Q. The Levitan Reports state that the PSEG nuclear units have not "incurred true out-of-pocket operational risk for the decade 2010 – May 2020." ***See, e.g.,*** **Salem II Report at 21. Is that accurate?**

A. No. In support of this statement, Levitan cites to PSEG's historical cost data (HC-ZEC-FIN-0002; S1-ZEC-FIN-0002; S2-ZEC-FIN-0002). Although "operational risk" does not appear as a line item in this data, it is reflected in the realized results. Operational risk is a forward-looking concept that recognizes the possibility that unexpected events might impact the operation of the unit. Even if a risk turns out not be realized in a given year, the risk still existed, and the exposure to risks going forward thus is an important consideration in business planning.

Q. What is PSEG's calculated total cost of operational risk?

A. The total cost of operational risk is approximately **[BEGIN CONFIDENTIAL]**[redacted]. **[END CONFIDENTIAL]** The table below shows operational risk for each unit: **[BEGIN CONFIDENTIAL]**

	Hope Creek	Salem I	Salem II	MWh-Weighted Average
Operational Risk per MWh	[redacted]			

[END CONFIDENTIAL]

Q. Does Levitan provide an alternative estimate of operational risk?

A. No. Instead, Levitan suggests that operational risk should be zero. That implies that a nuclear plant has no risk at all of experiencing an unexpected regulatory mandate, no risk at all of experiencing an equipment failure that requires unexpected costs to repair, and no risk at all of being forced out of service unexpectedly for an extended period. That position is illogical and contradicts both the ZEC Act and the Board's Decision in the ZEC1 proceeding to abide by the ZEC Act's clear instruction to consider those risks in evaluating financial need. *See* BPU *Order Determining the Eligibility of Hope Creek, Salem 1, and*

Salem 2 Nuclear Generators to Receive ZECs, April 18, 2019 Order at 13-15. Of course nuclear units face these risks, as recognized in both the ZEC Act and the Board's Decision, and significantly so, as the examples provided in discovery and discussed in Mr. Fricker's testimony demonstrate. It would be irrational for a nuclear plant owner to ignore these risks when making its business planning decisions.

To put the point another way, as discussed above, no business owner will operate a business that is expected to just cover its costs if there are no unexpected expenses. Instead, a business must generate sufficient revenue to make it worthwhile to take on the risk that there will be unexpected expenses. To suggest otherwise is tantamount to asserting that an investor in a nuclear generator requires a 0% rate of return. In fact, in the ZEC1 proceeding, Levitan suggested that a return of 12.8% would be reasonable. By analogy, it is equally unreasonable to assert that a nuclear generator bears no costs of risks, or that risks should not be considered when assessing the level of revenue needed for a nuclear plant to remain in operation.

B. <u>Market Risk</u>

1. <u>Overview of Market Risks</u>

Q. What is market risk?

A. The ZEC Act provides that "'market risks' shall include, but need not be limited to, 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." N.J.S.A. 48:3-87.5(a).

Q. Can you explain what is meant by "the risk of a forced outage and the associated costs arising from contractual obligations"? *See* N.J.S.A. 48:3-87.5(a).

A. Forced outage risk is the risk that a facility will experience an outage and consequently replacement electricity will need to be procured from the spot market, either physically or financially, in order to satisfy contractual obligations undertaken in an effort to hedge against spot market price volatility.

All other things equal, the spot market price will tend to rise when a nuclear plant is out of service. That is because the forced outage of a large baseload unit will require reliance on higher priced units to fill the supply gap. The cost associated with covering a forward obligation by purchasing from the spot market, including the risk of doing so at elevated prices, is encompassed by the statutory reference to "the risk of forced outage and the associated costs arising from contractual obligations." *See* N.J.S.A. 48:3-87.5(a).

Q. Focusing next on the market "risk that output from the nuclear power plant may not be able to be sold at projected levels," N.J.S.A. 48:3-87.5(a), can you explain how that risk arises despite hedging practices?

A. Although hedging can partially mitigate the risk that prices will fall, it does not fully mitigate that risk.

First, nuclear plants produce enormous output, and it is not possible to sell the full output in forward contracts all at once without adversely affecting forward energy prices. Accordingly, we gradually contract forward for the expected output of PSEG's generating plants over a multi-year horizon. As a result, we still bear the risk that forward prices will fall prior to the time at which all projected output is hedged—as has happened over most of the past decade, as we show graphically in the following section.

The second type of risk that output from the nuclear power plant may not be able to be sold at projected levels arises from the fact that the forward energy contracts commonly used to hedge market risk rely on the price for energy at a particular hub, rather than the price at the location of the plant. In PJM, the most liquid and commonly-traded forward energy contracts are associated with the PJM Western Hub, which averages prices from nodes in Pennsylvania, Maryland, and the District of Columbia. We hedge ratably at the PJM Western Hub, over a three-year horizon. It is also possible to enter into forward zonal energy contracts that are more strongly correlated with a particular generating unit. However, those contracts are more limited in liquidity, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

The price that a PSEG nuclear plant actually receives when it sells the energy produced is the locational marginal price ("LMP") at the plant, which reflects the balance of supply and demand at the location of plant itself, after taking into account transmission congestion and losses. As a result, the price at the plant fluctuates relative to locations at which forward energy hedge contracts can be traded. Financial Transmission Rights ("FTR") instruments can provide a hedge to the volatility of the congestion component of the LMP differential between the plant and the locations at which forward energy hedge contracts can be traded, but they do not hedge the other LMP differential component – marginal losses. In addition, FTR auctions are limited in frequency, hedge horizon, and liquidity, as there are no "natural buyers" for large amounts of energy at precisely the plant location.

Q. Is PSEG exposed to any other types of market risks?

A. Yes. The two categories of risk just described relate to risks in the energy market. However, PSEG is also exposed to risks in the capacity market. Specifically, PSEG bears several types of risks related to capacity revenues, including: (i) price forecast risk, (ii) capacity performance risk; and (iii) the risk that implementation of PJM's Minimum Offer Price Rule ("MOPR") may cause PSEG units to not clear the capacity auction in one or more energy years.

I note that capacity market risk was not material at the time of the initial ZEC eligibility period, because PJM had already conducted the capacity auctions for the relevant time periods. Therefore, the results of those auctions were built into PSEG's expectations at the time it submitted its first ZEC Application, and no cost of market risk was included for capacity. However, as of the date of this testimony, PJM has not yet conducted the capacity auction applicable to energy years 2022/2023 through 2024/2025. As a result, PSEG now bears a risk that the results of the capacity auction will differ from its expectations.

As of the date of this testimony, FERC has determined that a "minimum offer price" – essentially a bid price floor – will apply to all existing resources that receive a state subsidy. Different bid price floors will be calculated for different categories of generators, and fluctuations in the energy forward prices will impact the MOPR bid price floor applicable to nuclear units, which in turn will impact their ability to clear in the capacity auction.

Q. For purposes of evaluating PSEG's eligibility for ZECs, is it relevant that other types of merchant generators may experience market risks, as the Levitan Reports imply? *See, e.g.,* Salem II Report at 23.

A. No, for purposes of evaluating PSEG's eligibility for ZECs, it is not relevant whether other merchant generators are exposed to market risks. First, the ZEC Act does not require the risks to be unique to nuclear plants in order to be appropriately considered. Second, as discussed above, nuclear plants are more sensitive to market risk than other types of generators because they produce such large volumes of energy and because it is not feasible to modulate their level of production or their costs related to the plant in response to market signals.

Finally, and most importantly, the question in this proceeding is whether the market risks, together with the costs and operational risks, are too high for PSEG to keep the plants in operation without a $10/MWh ZEC. Other plants may also experience market risks, but they also have different costs, different revenue projections, and they face a different set of operational risks—and taken together, it may make sense for these plants to remain in operation notwithstanding the market risks they face. But in light of the high fixed costs faced by PSEG's nuclear units, the operational and market risks that nuclear units face, and the revenue projections for these nuclear units, these nuclear units will not remain in operation without a $10/MWh ZEC.

2. Quantifying Market Risk

Q. Please describe, at a high level, how PSEG calculated the cost of market risk.

A. PSEG used the same software, inputs, and modeling approach to calculate the cost of market risks for this proceeding as it uses in the ordinary course of business.

PSEG's Financial Risk Management Practice requires PSEG to assess and manage market risk at the 95% confidence level. The use of the 95% confidence interval is reasonable, and supported by guidance from the Securities and Exchange Commission for financial reporting purposes, which directs that, "absent economic justification for the selection of different confidence intervals, registrants should use intervals that are 95 percent or higher."[10]

PSEG modeled energy market risk and capacity market risk.

Q. How did PSEG model energy market risk?

A. In order to calculate energy market risk, PSEG modeled: (i) forced outage risk; (ii) energy price volatility risk; and (iii) the impact of our hedging practices on these risks. Each type of risk is described in more detail below.

Q. How did PSEG model the first component of energy market risk – the risk associated with forced outages?

A. PSEG's model jointly simulated generation outages along with prices to develop a probability distribution of forced outage risk. The average forced outage rate in the model is consistent with the forced outage rates in PSEG's business plan, and the uncertainty around that forced outage rate is consistent with the historical distribution of outages. The model measures the distribution of cost or benefit of needing to cover a forced outage in the spot market, spread over the unit's planned output.

Q. How did PSEG model the second component of market risk – the risk associated with energy price volatility?

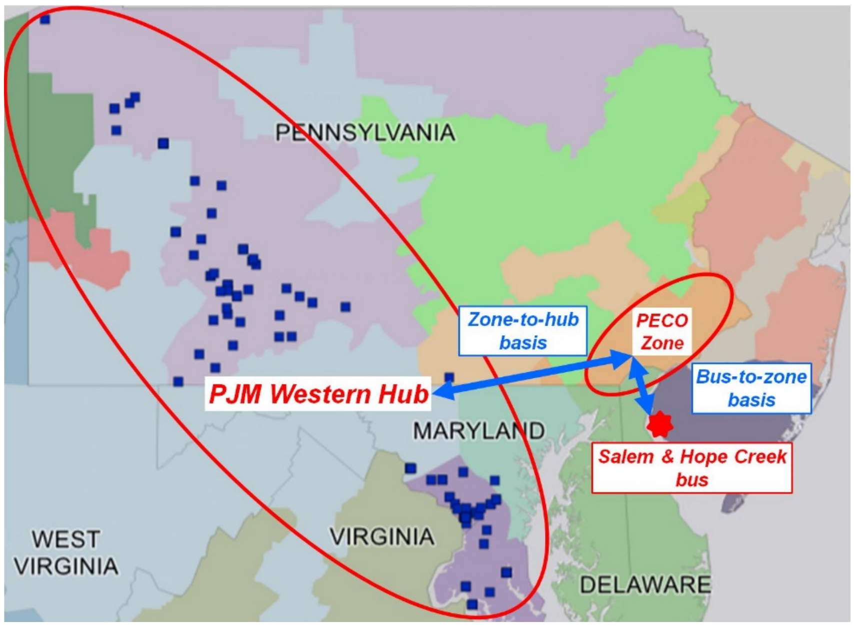
A. Price volatility risk is the risk that the price at which the nuclear plant's output is actually sold deviates from expectations, after taking hedges into account. Thus, PSEG's model of

---

[10] *See* ZEC2-HC-SECJ-FIN-0018 at 3, *citing* 17 C.F.R. Section 229.305, Instructions to paragraph 305(a), Instruction 4.A.

energy price volatility takes into account both the variability of the LMP – the price at which the plants' output will be sold – as well as our hedging strategy.

PSEG modeled the expected future LMP at each unit using three components: (i) the hub price; (ii) the zone-to-hub basis price; and (iii) a bus-to-zone price differential. These components are illustrated in the graphic below.



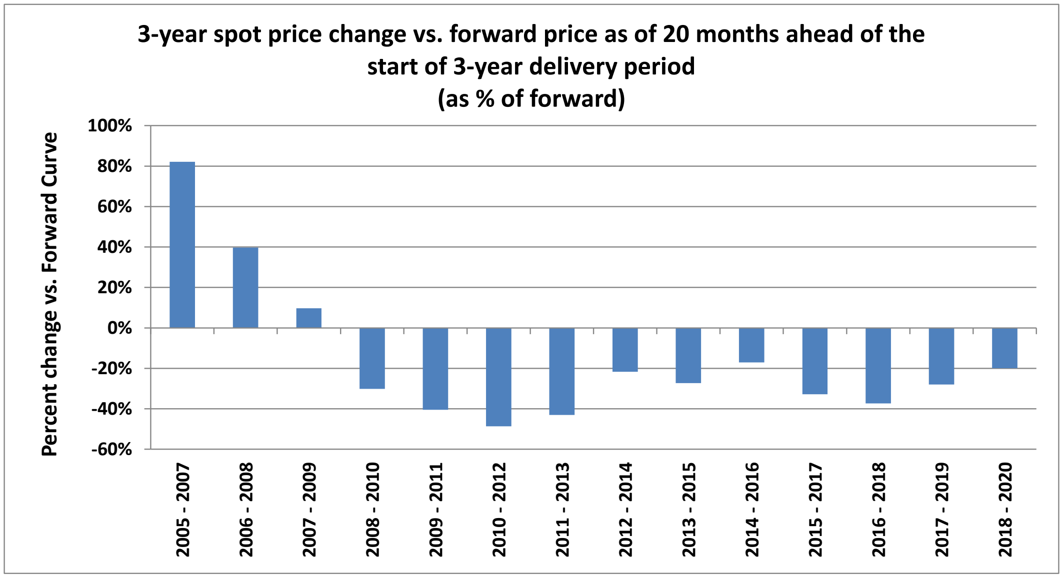
PSEG jointly modeled the volatility of prices for the PJM Western Hub, zone-to-hub basis, and bus-to-zone, based on market data. The resulting overall energy price risk at the Hope Creek and Salem bus is $9.05/MWh (unhedged), at the 95% confidence level.

Q. Can you please put this energy price risk in perspective?

A. Yes. To put that risk in perspective, the forward price expectation for the Hope Creek and Salem units is $24.70/MWh for the ZEC2 period. The $9.05/MWh downside price risk represents a price decrease of approximately 37% compared to forward energy prices for that period.

Q. Is that level of risk unusual from a historical perspective?

A. No. The graph below shows the actual difference between realized LMPs and forward price expectations 20 months before the start of the three-year delivery period, dating back to the three-year period 2005-2007.



As you can see, a 37% decrease between forward expectations and realized LMPs is well within the range of historical outcomes.

Q. You noted that the level of risk described above is unhedged. Can some of this risk be mitigated through hedging?

A. Yes, some risk can be mitigated through hedging. PSEG's modeled energy market risk values reflect the impact of our hedging practices on energy market risk. Details concerning the manner in which we hedge each component of energy market risk are provided in PSEG's responses to FIN-0018.

Q. How were hedging practices incorporated into your model of energy market risk?

A. PSEG's model assumes that we will add hedges ratably over time to achieve target hedging levels of 100% for forward energy sales of PJM West **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

As a result, the risk model includes the price exposure we experience prior to the time of the anticipated hedge, but reflects the risk mitigation resulting from the hedge from that point onward through delivery.

Q. How did PSEG model capacity market risk?

A. In order to model the risk that the MOPR may prevent a unit from clearing the PJM capacity auction, PSEG first models the MOPR consistent with PJM's proposed methodology. PSEG's model incorporates capacity revenue scenarios in which the impact of the MOPR bid price floor for each iteration of the simulation is calculated based on the same PJM Western Hub energy prices used to estimate the energy market outcome for that iteration.

Based on the anticipated structure of the MOPR, PSEG estimated that the PJM Western Hub forward price below which the MOPR would cause the nuclear facilities to fail clear the capacity auction is approximately **[BEGIN CONFIDENTIAL]** [redacted].[11] **[END CONFIDENTIAL]**

---

[11] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

As noted above, PSEG bears other risks related to capacity, including price forecast risk and capacity performance risk.

Q. Is there an effective means of mitigating capacity market risk?

A. No, because the MOPR dictates the minimum price at which PSEG must bid in the auction.

Q. What is the total cost of market risk, including both energy and capacity market risks?

A. The total cost of market risks is **[BEGIN CONFIDENTIAL]** [redacted] **/[END CONFIDENTIAL]**MWh. The table below provides the total market risk for each unit:

[BEGIN CONFIDENTIAL]

	Hope Creek	Salem I	Salem II	MWh-Weighted Average
Market Risk per MWh	[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

C. <u>Conclusions Regarding Risks</u>

Q. Altogether, what subsidy would PSEG need to cover its costs and risks?

A. The table below calculates the level of subsidy that is required to cover the full value of PSEG's costs, operational risks, and market risks. When PSEG filed its October 1, 2020 applications for Hope Creek, Salem I, and Salem II, it based the energy revenues on forward prices as of May 29, 2020. In responses to discovery questions (PS-9 and PS-11), adjustments were made to reflect energy pricing as of September 30, 2020 and PSEG's forecasted costs as of the end of October 2020. Those adjustments are reflected in the following table: **[BEGIN CONFIDENTIAL]**

	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Q. It appears that PSEG's overall need is greater than it can obtain through the ZEC program. Why is PSEG willing to stay open even for a $10/MWh ZEC?

A. We understand that these plants are an important economic asset for the State of New Jersey, as well as a key to making our clean energy future affordable. As a result, it is our aim to continue to work in partnership with the State and keep the plants running, despite the economic challenges. However, we believe that a longer-term solution that values the clean energy attributes of the plants is necessary.

Q. Would PSEG continue to operate the plants if it received ZECs of less than $10/MWh?

A. No, it would not. Consider that if PSEG receives ZECs at the statutory maximum value of $10/MWh, PSEG's ROE will be approximately in the range of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** Moreover, without ZECs, PSEG's ROE will be significantly negative.

Q. Would that [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL] figure be reasonable for these plants?**

A. No, it would not. As the Board is no doubt aware, a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** ROE would not be considered reasonable as applied to a regulated public utility. And merchant generators like PSEG bear more risk than regulated public utilities, and so require a higher rate of return to attract capital.

Q. Is there any precedent establishing an appropriate ROE for investment in an operating nuclear power plant?

A. Yes. In PJM's initial (April 19, 2018) quadrennial Cost of New Entry ("CONE") estimate, PJM's consultants estimated "a return on equity of 12.8%."[12] FERC found PJM's approach to be "transparent," with "well-supported" assumptions, and resulting in "a reasonable Cost of Capital that 'captures financial market conditions and appropriately balances investor and consumer interests.'"[13]

In its subsequent filing at FERC,[14] PJM revised its cost of equity to 13.0%.

---

[12] The Brattle Group, PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 19, 2018, available at https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx, at 35-36.

[13] *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183, at P 76 (2014) (quoting Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER14-2940-000, Attachment B at 5 (Nov. 6, 2014)).

[14] *PJM Interconnection, L.L.C.*, Docket No. ER19-105-000, Periodic Review Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters (October 12, 2018).

Q. Has Levitan opined on the PJM ROE for merchant generation plants that you describe above?

A. Yes, very favorably. In its report to the Board in the ZEC1 proceeding, Levitan acknowledged that "the determination of an appropriate 'risk-adjusted cost of capital' is typically contentious for merchant power plants." That Levitan Report nevertheless concluded that "PJM provided a useful proxy value," of 12.8%, and that the figures provided "will be useful metrics" if the Board requests any eligibility evaluation under the alternative criterion involving the risk-adjusted cost of capital.[15] Levitan also noted that "[o]lder return on equity values from both the NYISO and ISO-NE CONE studies are 13.4%, slightly higher than the PJM value," and concluded that "all of these values reflect long-term average equity returns," and that "merchant generators recognize they typically earn more in some years and less in other years."[16]

Q. The Levitan Reports assert that operational risks and market risks are "are not actually incurred as out-of-pocket costs," and so may not be avoided if the units cease operations. *See, e.g.*, Levitan Report on Salem II, at 2-3. Do you agree with this characterization?

A. I do not. Levitan's conclusion regarding operational and market risk—essentially concluding that such risks should be altogether ignored—contradicts both the ZEC Act and the Board's prior decision to abide by the ZEC Act's clear instruction to consider those risks in evaluating financial need. *See BPU Order Determining the Eligibility of Hope Creek, Salem 1, and Salem 2 Nuclear Generators to Receive ZECs*, April 18, 2019 Order at 13-15.

---

[15] That is, under the statutory option in the ZEC Act to establish qualification by demonstrating that the plant will not cover its costs and risks, or costs including risk-adjusted cost of capital.

[16] Levitan & Associates, Inc., New Jersey Zero Emission Certificate Application Eligibility Report, prepared for the New Jersey BPU (April 8, 2019), at 34.

Operational risk and market risk are entirely avoided if the units cease operation. Indeed, these risks only arise if the units continue to operate. If a unit does not operate at all, it does not bear any risk that a component will break, or that a prolonged outage will result increased cost per MWh. If a unit does not operate at all, it does not bear any risk that it will be unable to sell its output at anticipated levels, nor any risk that it will need to cover its contractual commitments due to a forced outage. The risks identified by the ZEC Act arise from operating a nuclear unit, and are avoided by shutting down the unit.

Indeed, I note that the Levitan Reports acknowledge that operational risk is "a prudent generation planning and asset management parameter," and characterize market risk as "a useful and valid planning parameter." *See, e.g.*, Salem II Report at 21, 23. On these points, I agree with Levitan. In fact, the prudence and validity of these metrics in the asset planning context simply underscores why they should be considered in evaluating the ZEC price. As discussed above, PSEG has a very important decision to make as we plan our business moving forward – whether or not to continue to operate these plants. The expected results and the risks around those results – all "prudent," "useful," and "valid" – are critical to that determination. Finally, as discussed in detail above, if the cost of risk is excluded from the calculus, the result will not incorporate any return. However, the ZEC Act indicates that a return component is appropriate, since it permits an applicant to calculate its ZEC need on a "cost plus return" basis.

Q. In the last ZEC proceeding, the IMM argued that the Avoided Cost Rate ("ACR") methodology was the appropriate methodology to measure a nuclear plant's costs and risks. Do you agree?

A. No. The ZEC Act does not provide for the IMM's ACR methodology. Rather, the ZEC Act requires the Board to consider costs plus certain specified operational and market risks.

The ACR methodology does not incorporate the costs of market risks, and does not account for all of the types operational risks described in the ZEC Act. Therefore, it is not an appropriate metric for use in evaluating the award of ZECs.

V. CONCLUSION

Q. Does this complete your testimony?

A. Yes.