Monitoring Analytics

CONFIDENTIAL

Analysis of NJ Zero Emissions Certificate (ZEC) Applications

The Independent Market Monitor for PJM

January 31, 2019

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Introduction

The May 23, 2018, New Jersey ZECs legislation directed the New Jersey Board of Public Utilities (BPU) to create a program and mechanism for the issuance of Zero Emission Credits (ZECs).[1] The Board approved the participation of the Independent Market Monitor for PJM (IMM) in the review of the ZECs applications:[2]

> [T]he Board acknowledges that the IMM is in a unique position to review the financial viability of nuclear power plants seeking ZECs based on its experience reviewing generators' costs in the PJM capacity markets as part of reviewing unit-specific competitive offers.

If approved on a plant by plant basis, ZECs would provide a subsidy to specific nuclear power plants based on the criteria established in the legislation and implemented by the BPU. The subsidy would be $10.00 per MWh of generation from the specific plants. The per MWh subsidy, paid as Nuclear Diversity Certificates (NDC), is calculated as the sum of non-bypassable payments by ratepayers of electric utilities at a rate of $.004 per KWh ($4.00 per MWh), unless reduced by the BPU, divided by the greater of 40 percent of the total MWh distributed by electric public utilities or the total generation of the selected nuclear power plants.[3] Dividing $4.00 per MWh by .40 equals $10.00 subsidy per MWh generated by each nuclear plant, given that the total generation of the three applicant nuclear units does not exceed 40 percent of the total MWh distributed by electric utilities in 2018.

The total subsidy, if Hope Creek 1 and Salem 1 and 2 received ZECs, based on expected generation over the three year period from June 1, 2019, through May 31, 2022, plus the period from April 19, 2019, through May 31, 2019, would be approximately [redacted] million.[4] The approximate annual subsidy would be [redacted] million for Hope Creek 1, [redacted] million for Salem 1 and [redacted] million for Salem 2.

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1 *I/M/O the Implementation of L.2018.c.16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants*, BPU Docket No. EO18080899 (Aug.29, 2018) ("ZEC Legislation").

2 *I/M/O the Implementation of L.2018.c.16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants*, BPU Docket No. EO18080899 (Nov. 19, 2018)("November 19th Order").

3 L. 2018, c. 16 (C.48:3-87.3–87.7)(S.B. 2313 § 3.a.i. (1)).

4 November 19th Order at 12.

The criteria for the BPU to determine the need for a subsidy are defined by the ZECs legislation. The criteria leave substantial discretion to the BPU. The criteria in the legislation state that the owner of the nuclear power plant must demonstrate to the satisfaction of the board, through the financial and other confidential information submitted to the board that the continued operation of the plant is at risk:[5]

> … because the nuclear power 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, and that the nuclear power plant will cease operations within three years unless the nuclear power plant experiences a material financial change…

The legislation includes two alternative criteria: not covering costs and risks; and not covering risk-adjusted cost of capital. The selection criterion must also lead to the conclusion that the nuclear power plant will cease operations within three years unless the plant experiences a material financial change. PSEG's and Exelon's applications are directed towards the first criterion.

The IMM uses net avoidable costs as the relevant metric for evaluating whether the identified units meet the criterion. Net avoidable costs equal market revenue minus avoidable costs. If avoidable costs are covered, the unit is covering its costs. The IMM's analysis focuses on the standard economics definition of whether an asset is receiving a retirement signal from the market. Under that definition, an asset is receiving a retirement signal from the market if the asset is not covering and is not expected to cover its avoidable costs on an annual basis. Avoidable costs are the costs incurred each year to keep a unit running. Avoidable costs include, for example, operation and maintenance expense but do not include the return on and of capital. As the legislation states, not covering avoidable costs means that a unit is "cash negative on an annual basis."[6]

The Board notes that there are potential conflicts based on initiatives at the federal and regional levels.[7] The BPU explains that the FERC has declared the PJM capacity market design to be unjust and unreasonable and the final FERC decision in that matter could significantly affect the regulatory and economic status of nuclear power plants with subsidies like the ZECs program.[8] The BPU also explains that the U.S. Department of Energy has taken actions that could lead to subsidies for nuclear power plants from

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5 L. 2018, c. 16 (C.48:3-87.3–87.7).

6 *Id.* (at S.B. 2313 § 3.a.).

7 See November 19th Order at 13.

8 See 163 FERC ¶ 61,236 (2018).

sources outside the PJM market and apart from the BPU and New Jersey actions. The BPU indicates that it is following these developments which could change the situation during the pendency of the ZECs proceeding at the BPU.

As the BPU recognized in the order, FERC is considering significant changes to the design of the PJM Capacity Market. Specifically, FERC is considering whether and how to modify the Minimum Offer Price Rule (MOPR).[9] Some of the proposed changes to the MOPR could significantly change prices in the capacity market, could significantly change the compensation of specific units, and could significantly change the way in which subsidized units would be treated in the PJM Capacity Market.

There are other developments that could significantly change PJM prices in the near term and could therefore significantly change the financial status of the units in question.

PJM is planning to propose changes to the capacity market to address what PJM believes are fuel security issues. The result could be an increase in capacity market prices.[10]

FERC has initiated a proceeding that may result in a change in the way in which the dispatch of so called fast start units affects prices in PJM.[11] If FERC accepts the changes proposed by PJM, energy market prices would increase in PJM.

PJM has a request pending at FERC to change the level of operation and maintenance costs includable in cost-based energy offers by PJM units.[12] PJM's proposal would significantly increase the level of cost-based offers and therefore increase the level of energy market prices in PJM. If PJM's proposal were adopted by FERC, energy market prices would increase in PJM.

PJM has stated that it plans to file a new approach to reserve and energy pricing, presented at the Energy Price Formation Senior Task Force (EPFSTF) and the Markets & Reliability Committee (MRC), that PJM estimates could increase energy prices by approximately five to ten percent.[13] [14] The IMM believes that this is a conservatively low

9 *Id.*

10 PJM. "Fuel Security Update," presentation the MRC on January 24, 2019. <https://www.pjm.com/-/media/committees-groups/committees/mrc/20190124/20190124-item-07-fuel-security-presentation.ashx>.

11 See FERC Docket No. EL18-34-000.

12 See FERC Docket No. EL19-8-000 & ER19-210-000.

13 Letter from PJM Board of Managers re EPFSTF "regarding improvements to reserve procurement and shortage pricing in the energy market," (Dec. 5, 2018), which can be accessed at: <*https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20181205-pjm-board-letter-re-price-formation.ashx?la=en*>.

estimate, in part because the time period of the simulation did not include extreme weather conditions but also because PJM's simulations did not include the interaction among fast start pricing, inclusion of higher operation and maintenance expenses and reserve pricing. If PJM's approach is adopted and energy market prices increase by 10 percent effective in 2020 for two of the three years, Hope Creek 1, Salem 1 and Salem 2 would earn a total of [redacted] million more in energy revenue than the PSEG projections over the period 2019-2021. A 20 percent increase in LMP would result in Hope Creek 1, Salem 1 and Salem 2 earning [redacted] million more in energy revenue than is shown in PSEG's projections over the period 2019-2021. The total subsidy requested for Hope Creek 1 and Salem 1 and 2 for the three year period is approximately [redacted] million.[15]

Given that PJM plans to file its reserve and energy pricing proposal with FERC in the next month with a target effective date of 2020, given that the fast start pricing and operations and maintenance proposals have been at FERC for some time, and given that the resultant price increases from the reserve and energy pricing proposal alone or with the other proposals would be a significant offset to the maximum subsidy level and a material financial change in the status of the applicant units, the IMM recommends that, even if the BPU believes a subsidy is required at current energy market price levels, the BPU consider waiting for a final FERC determination on the pending cases at FERC that could significantly change market design and financial results for nuclear power plants. This would mean rejecting the ZECs requests to be effective in 2019 and evaluating a new set of requests after the FERC decision.

In order to provide a subsidy, the BPU must determine that the plant is at risk of closing unless the nuclear power plant experiences a material financial change. There are multiple paths under active consideration by FERC under which nuclear plants could experience a material financial change in the next 12 to 18 months.

The ZECs decision is binary. The ZECs are approved at a level of $10.00 per MWh for three years or the ZECs are not approved. Unit owners have an ongoing option to apply and reapply for subsidies even if rejected while, once the decision is made to provide a subsidy, ratepayers must pay the full amount for three years, regardless of changes in circumstances. Given that the IMM has not identified a need for a subsidy and given that PJM, FERC and DOE actions could offset the requested ZECs subsidy levels, it would be reasonable for the BPU to wait until after the FERC decisions on PJM's requests and for PSEG and Exelon to refile the request next year if PSEG considers it necessary.

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14 See PJM, EPFSTF. *Price Formation.* p. 19-22. PJM report to the EPFSTF (Dec. 14, 2018), which can accessed at: <*https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-04-price-formation-paper.ashx*>.

15 November 19th Order.

Summary of results

The analysis in this report focuses primarily on the data and details of PSEG's application. Hope Creek 1 is fully owned by PSEG. Salem 1 and Salem 2 are jointly owned by PSEG (57 percent) and Exelon (43 percent). PSEG is the operator of the Hope Creek 1, Salem 1 and Salem 2 units. PSEG has access to all the costs and revenues associated with the operation of these units. The analysis in this report addresses the filings of both PSEG and Exelon. [redacted]

All tables show the analysis for the entire Hope Creek 1 unit, the entire Salem 1 unit, and the entire Salem 2 unit.

PSEG overstates its need for subsidies for the Hope Creek 1 and Salem units. PSEG understates forward energy revenues, understates capacity revenues, overstates costs and overstates the cost of risk. PSEG's requested subsidies are slightly [redacted] than the level of the potential ZECs subsidies for Hope Creek 1 and Salem 2 and slightly [redacted] for Salem 1. The ZEC subsidy level is $10.00 per MWh while PSEG claims to have demonstrated the need for subsidy levels of [redacted] per MWh for Hope Creek 1, [redacted] per MWh for Salem 1, and [redacted] per MWh for Salem 2.

Table 1 includes summary results of the analysis for the Hope Creek 1 unit, the Salem 1 unit and the Salem 2 unit. For each unit, PSEG's position and the IMM's position on MWh of generation, revenues, costs, net revenues and required subsidy are presented. A subsidy is requested by PSEG/Exelon if the subsidy number in the table is a positive. The unit is covering its avoidable costs in the IMM analysis if the net avoidable cost number is a negative. Net avoidable costs as used in this report equal avoidable costs minus revenues.

In summary, the IMM concludes that the Hope Creek 1, Salem 1 and Salem 2 units are expected to more than cover their avoidable costs over the next three years. As a result, none of the units meets the standard for a subsidy under the ZECs program. The nuclear power plants are expected to fully cover their costs and risks.

Table 1 Summary analysis for Hope Creek 1, Salem 1 and Salem 2

	2019	2020	2021	2019	[redacted]
[redacted]					
[redacted]					
[redacted]					
[redacted]					
[redacted]					
[redacted]					

Table 2 includes summary results of the analysis for the Hope Creek 1 unit. Detailed information on the differences between each line item of the PSEG and IMM forward looking revenues and costs for Hope Creek 1 can be found in subsequent sections.

Table 2 Line item detail: Hope Creek 1

PSEG Projections	IMM [redacted]
[redacted]	[redacted]

Table 3 includes summary results of the analysis for the Salem 1 unit. Detailed information on the differences between each line item of the PSEG and IMM forward looking revenues and costs for Salem 1 can be found in subsequent sections.

Table 3 Line item detail: Salem 1

PSEG Projections	IMM Analysis
[redacted]	[redacted]

Table 4 includes summary results of the analysis for the Salem 2 unit. Detailed information on the differences between each line item of the PSEG and IMM forward looking revenues and costs for Salem 2 can be found in subsequent sections.

Table 4 Line item detail: Salem 2

PSEG Projections	IMM [redacted]
[redacted]	[redacted]

The primary differences between the IMM analysis and the PSEG/Exelon subsidy request result from differences in revenues and in risk adders. For energy revenues, the IMM uses generation consistent with historical generation, accounting for two refueling outages in the three year period, and energy prices consistent with forward prices as of the last business day of 2018, December 28, 2018. For capacity revenues, the IMM uses the full UCAP of Hope Creek 1, Salem 1, and Salem 2 at BRA clearing prices. For risk adders, the IMM uses zero.

With only these three modifications to the PSEG calculations, the IMM analysis shows that Hope Creek 1, Salem 1, and Salem 2 will more than cover their avoidable costs for the three year period 2019-2021 and therefore do not qualify for subsidies.

Revenues

Energy Market Revenues

Projected energy market revenues are a function of projected unit MWh generation and projected energy prices. Projected generation and projected prices affect gross energy revenues, unit net revenues, net coverage of avoidable costs, and the final $/MWh subsidy request.

Generation

Hope Creek 1, Salem 1 and Salem 2 are all on an 18 month refueling schedule and are on outage for approximately one month for each refueling. For example, one unit will have a refueling outage in the spring of year 1, the fall of year 2 and no refueling outage in year 3. The cycle would start over in the spring of year 4. In any given three year period, each unit will have two refueling outages. For a large unit that generally operates at full output, a refueling outage and its associated lower revenues and higher costs can cause large year to year differences using $/MWh as the metric because both the numerator and denominator vary as a result of refueling outages. The total dollars of costs and revenues over a three year period $/MWh are the metrics when evaluating the results of the financial analysis of the units at issue. All tables include both total dollars and $/MWh over the period 2019-2021.

Projected generation output is a function of the unit's size and the hours in which the unit operates, which are total hours in the year net of outage hours. PSEG's projected generation for the three nuclear units is [redacted] than expected based on the actual historical generation from these units.

In addition, Hope Creek 1, Salem 1, and Salem 2 take refueling outages during the shoulder months in the spring and fall, when prices tend to be lower. Projected energy market revenues are calculated as the projected unit MWh generation multiplied by the projected energy prices. The IMM's use of the average annual bus price to calculate projected energy revenues understates energy revenues in refueling years. In refueling years, the unit will receive a higher average price than the average annual bus price for its generation because the unit will be on a refueling outage during a low-priced month.

For Hope Creek 1, PSEG's projected generation in years with [redacted] the overall projected generation is [redacted] than expected based on the unit's actual 10 year historical generation as shown in Table 5 and Table 6.

For Salem 1 and Salem 2, PSEG's projected generation is [redacted] than the units' actual average historical generation, [redacted] as shown in Table 7, Table 8, Table 9 and Table 10.

Accounting for refueling outages, using the 10 year average generation for expected generation results in [redacted] generation than PSEG's projections.

Table 5 Unit generation 2008-2017: Hope Creek 1

[redacted]

Table 6 Unit generation 2019-2021: Hope Creek 1

[redacted]

Table 7 Unit generation 2008-2017: Salem 1

[redacted]

Table 8 Unit generation 2019-2021: Salem 1

[redacted]

Table 9 Unit generation 2008-2017: Salem 2

[redacted]

Table 10 Unit generation 2019-2021: Salem 2

[redacted]

Prices

Projected energy prices are based on forward energy markets. Forward markets provide a market source of future prices based on the expectations of market participants buying and selling power. Liquid forward prices provide the best indication of expected prices because they incorporate the expectations of more market participants. PJM West Hub is the most liquid forward market in PJM. Hope Creek 1 and Salem 1 & 2 are located at individual buses in PJM, and the forward market price must reflect the locational price differences (basis difference) between the PJM West Hub price and the unit bus price.

The IMM used the forward prices for West Hub as of December 28, 2018, the last business day in 2018, and the defined basis difference between West Hub and the Hope Creek 1/Salem 1/Salem 2 bus in 2018 to calculate the forward prices at the bus for the period 2019 through 2021.

PSEG calculated projected energy prices at the bus based on the forward prices at the [redacted]

Forward prices vary with the date on which the forward energy prices are observed and with the period used to calculate the basis adjustment. In the past three years, Hope Creek 1/Salem 1/Salem 2 bus prices have been lower than both West Hub and [redacted] prices. PSEG calculated forward prices as of September 28, 2018. The forward prices for 2019-2023 as of the last business day of 2018, December 28, 2018, were higher than the forward prices as of September 28, 2018.

If projected energy revenues are calculated using historical average generation, adjusted for refueling outages, and forward prices as of December 28, 2018, Hope Creek 1 would earn [redacted] million more in energy revenue than PSEG's projections over the period 2019-2021, Salem 1 would earn [redacted] million more in energy revenue than is shown in PSEG's projections over the period 2019-2021, and Salem 2 would earn [redacted] million more in energy revenue than is shown in PSEG's projections over the period 2019-2021. Table 11, Table 12 and Table 13 show the results of adjusting both projected generation and forward bus prices.

Table 11 Energy revenue 2019-2021: Hope Creek 1

[redacted]

Table 12 Energy revenue 2019-2021: Salem 1

[redacted]

Table 13 Energy revenue 2019-2021: Salem 2

[redacted]

PJM has stated that it plans to file a new approach to reserve pricing that PJM estimates could increase energy prices by about $1.92 billion per year, based on PJM simulations.[16] [17] The IMM believes that this is a conservatively low number, in part because the time period of the simulation did not include extreme weather conditions but also because PJM's simulations did not include the interaction among fast start pricing, inclusion of higher operation and maintenance expenses and reserve pricing.[18] [19] [20] The $1.92 billion is an approximately five to ten percent increase in energy market revenues over total energy market revenues in 2017 and 2018.

If PJM's approach is adopted and energy market prices increase by 10 percent starting in 2020, Table 14 shows that Hope Creek 1 would earn [redacted] million more in energy revenue than the PSEG projections over the period 2019-2021. A 20 percent increase in energy market prices would result in Hope Creek 1 earning [redacted] million more in energy revenue than in PSEG's projections over the period 2019–2021.

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16 Letter from PJM Board of Managers re EPFSTF "regarding improvements to reserve procurement and shortage pricing in the energy market," (Dec. 5, 2018), which can be accessed at: <*https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20181205-pjm-board-letter-re-price-formation.ashx?la=en*> .

17 See PJM report to the Energy Price Formation Senior Task Force (EPFSTF) (Dec.14, 2018) at 19–22, which can be accessed at: <*https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-04-price-formation-paper.ashx*>.

18 PJM Interconnection, L.L.C. FERC Docket No. EL18-34-000.

19 PJM Interconnection, L.L.C., FERC Docket No. EL19-8 & ER19-210.

20 Letter from PJM Board of Managers re EPFSTF "*regarding improvements to reserve procurement and shortage pricing in the energy market*," (Dec. 5, 2018), which can be accessed at: <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20181205-pjm-board-letter-re-price-formation.ashx?la=en>.

Table 14 Estimated effect of LMP increases: Hope Creek 1

[redacted]

If PJM's approach is adopted and energy market prices increase by 10 percent starting in 2020, Table 15 shows that Salem 1 would earn [redacted] million more in energy revenue than the PSEG projections over the period 2019-2021. A 20 percent increase in energy market prices would result in Salem 1 earning [redacted] million more in energy revenue than in PSEG's projections over the period 2019-2021.

Table 15 Estimated effect of LMP increases: Salem 1

[redacted]

If PJM's approach is adopted and energy market prices increase by 10 percent starting in 2020, Table 16 shows that Salem 2 would earn [redacted] million more in energy revenue than the PSEG projections over the period 2019-2021. A 20 percent increase in energy market prices would result in Salem 2 earning [redacted] million more in energy revenue than in PSEG's projections over the period 2019-2021.

Table 16 Estimated effect of LMP increases: Salem 2

[redacted]

Capacity Market Revenues

[redacted] Cleared sell offers and make whole MW in RPM Auctions are binding commitments for the capacity obligation and capacity payment for the relevant delivery year. [redacted]

The IMM analysis addresses these issues by applying the Base Residual Auction prices to the full capacity of Hope Creek 1, Salem 1 and Salem 2. The BRA price is the best metric and a conservative metric for the market value of the entire capacity from these three units. [redacted] If Hope Creek 1 [redacted] in each BRA at the BRA clearing price, Hope Creek 1 [redacted] than included in PSEG's projections for the three calendar years 2019-2021. If Salem 1 [redacted] in each BRA at the BRA clearing price, Salem 1 [redacted] than included in PSEG's projections for the three calendar years 2019-2021. If Salem 2 [redacted] in each BRA at the BRA clearing price, Salem 2 [redacted] than included in PSEG's projections for the three calendar years 2019-2021.

Table 17, Table 18 and Table 19 show the capacity offered in the BRA, the capacity cleared in the BRA, and the BRA clearing price.

Table 17 Capacity offered, capacity cleared, and BRA capacity clearing prices: Hope Creek 1

Delivery [redacted]

Table 18 Capacity offered, capacity cleared, and BRA capacity clearing prices: Salem 1

[redacted]

Table 19 Capacity offered, capacity cleared, and BRA capacity clearing prices: Salem 2

[redacted]

In the PJM Capacity Market, delivery years begin on June 1 and end on May 31. For example, the BRA in 2018 was for the 2021/2022 Delivery Year, from June 1, 2021, through May 31, 2022. All BRA capacity prices are known for the calendar years 2019, 2020, and 2021. Capacity revenues are converted to calendar year dollars in Table 20, Table 21 and Table 22.

Table 20 Capacity revenue 2019-2021: Hope Creek 1

[redacted]

Table 21 Capacity revenue 2019-2021: Salem 1

[redacted]

Table 22 Capacity revenue 2019-2021: Salem 2

[redacted]

Sensitivity Analyses of Revenue Adjustments

The IMM adjustments to PSEG's forecast revenues, based on the appropriate level of generation output, forward prices, energy market revenues and capacity market revenues, result in an increase over PSEG's forecast revenues for all units, as shown in Table 23, Table 24 and Table 25.

Hope Creek 1 adjusted revenues are [redacted] million higher [redacted] percent) than the revenues used by PSEG over the three year period from 2019 through 2021.

Table 23 Revenue summary analysis: Hope Creek 1

[redacted]

Salem 1 adjusted revenues are [redacted] million higher [redacted] percent) than the revenues used by PSEG over the three year period from 2019 through 2021.

Table 24 Revenue summary analysis: Salem 1

[redacted]

Salem 2 adjusted revenues are [redacted] million higher [redacted] percent) than the revenues used by PSEG over the three year period from 2019 through 2021.

Table 25 Revenue summary analysis: Salem 2

[redacted]

Costs

Risk Adders

PSEG asserts that their need for a subsidy is higher than supported by actual costs and revenues. PSEG asserts that ratepayers should hold it harmless from two types of risk by paying higher subsidies. PSEG is requesting that ratepayers hold it harmless from reductions in revenues and increases in costs. [redacted] In proposing risk adders, PSEG is requesting that ratepayers not only cover its costs, but that ratepayers should pay an additional [redacted] percent in case costs are higher or revenues lower.

PSEG asserts that the company faces operational risk [redacted] PSEG adds an operational risk premium to the requested subsidy to be paid by ratepayers. PSEG asserts that the company faces market risk [redacted] PSEG adds a market risk premium to the requested subsidy to be paid by ratepayers.

For all three units, PSEG's proposed risk adders alone would increase the asserted need for a subsidy by [redacted] million over the three year period 2019-2021, a [redacted] percent increase over actual costs, and [redacted] percent of the requested subsidy. For Hope Creek 1, [redacted]/MWh of the [redacted]/MWh requested subsidy is the risk adders, or [redacted] percent. For Salem 1, [redacted]/MWh of the [redacted]/MWh requested subsidy is the risk adders, or [redacted] percent. For Salem 2, [redacted]/MWh of the [redacted]/MWh requested subsidy is the risk adders, or [redacted] percent.

New Jersey ratepayers should not be asked to guarantee revenues and costs for the identified units by paying additional subsidies to PSEG and Exelon. PSEG does not incorporate the probability of costs being lower than expected. [redacted] PSEG does not explain why they do not incorporate the probability of revenues being higher than expected. [redacted] PSEG does not address the expected positive impact of the proposed PJM changes on energy market prices. PSEG does not address the fact that the structure of the subsidy would provide PSEG guaranteed increases in revenues over three years regardless of whether PSEG's costs go down and revenues go up. PSEG's and Exelon's risk adders do not constitute a cost of risk. The operational costs incurred by PSEG include the costs of maintaining the safety of the unit and minimizing the risks of operating the units. These costs are included in the costs of the unit evaluated in this report and are covered by revenues.

PSESG's proposed risk adders would increase the asserted need for a subsidy for Hope Creek 1 by [redacted] million over the three year period 2019-2021, a [redacted] percent increase over actual costs, as shown in Table 26.

Table 26 Historical costs and the scale of proposed risk adders: Hope Creek 1

[redacted]

PSESG's proposed risk adders would increase the asserted need for a subsidy for Salem 1 by [redacted] million over the three year period 2019-2021, a [redacted] percent increase over actual costs, as shown in Table 27.

Table 27 Historical costs and the scale of proposed risk adders: Salem 1

Salem 1	2013	2014	2015	2016	2017	2013-2017	2019	2020	2021	2022	2023	2019-2021
[redacted]												

PSESG's proposed risk adders would increase the asserted need for a subsidy for Salem 2 by [redacted] million over the three year period 2019-2021, a [redacted] percent increase over actual costs, as shown in Table 28.

Table 28 Historical costs and the scale of proposed risk adders: Salem 2

[redacted]

Operational Risk Adder

[redacted]

Market Risk Adder

[redacted]

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21 PSEG response [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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22 See [redacted]

Operating Costs

The Electric Utility Cost Group (EUCG) Nuclear Committee is a cooperating group of nuclear plant representatives. Their primary goal is to optimize costs and reliability performance of participating plants. To achieve these objectives, the Nuclear Committee maintains a database for comparing nuclear plant costs, staffing, and performance data. This database was originally developed in 1986 and EUCG states that it is the best, most comprehensive source of nuclear plant data. This database is updated annually and includes comprehensive nuclear performance and cost data, including operating costs, capital costs, and fuel costs.[23]

The Nuclear Energy Institute (NEI) is the Washington, D.C. based policy organization of the nuclear industry. NEI publishes a report annually on nuclear costs using data from EUCG. In October 2018, NEI published the latest version of a report, Nuclear Costs in Context, including average operating costs, capital expenditures, and fuel costs for the U.S. nuclear fleet for 2017.[24] The source for this data is the EUCG. NEI describes the costs submitted to EUCG and reported by NEI as: "Total generating costs include capital, fuel and operating costs — all the costs necessary to produce electricity from a nuclear power plant."[25]

PSEG provided 2017 operating cost data for Hope Creek 1, Salem 1, and Salem 2 to EUCG. For all units, the operating costs provided by PSEG to EUCG are [redacted] operating costs in PSEG's projections in the request for subsidies. Based on the line item details PSEG provided [redacted] in their subsidy request, [redacted] the costs that PSEG [redacted] EUCG costs are [redacted][26] [redacted]

The IMM analysis treats the annual capital expenditures included in PSEG's operating costs as expenses rather than the usual accounting treatment of capital expenditures

23 Electric Utility Cost Group. Nuclear Committee. (Jan. 28, 2019) <https://www.eucg.org/committees/nuclear.cfm>.

24 Nuclear Energy Institute (Oct. 19, 2018). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-context-201810.pdf> .

25 *Id.*

26 The line item adjustment for [redacted]

which would recognize that they are recovered over the life of the asset. The IMM's approach increases operating costs compared to the alternative.

In 2017, the total operating costs included in PSEG's ZEC application for Hope Creek 1 submitted to EUCG for Hope Creek 1 were [redacted] the operating costs provided in support of the subsidy request in PSEG's ZEC application. For the Salem units (Salem 1 & Salem 2), the total operating costs submitted to EUCG [redacted] the operating costs provided in support of the subsidy request in PSEG's ZEC application.

Table 29 shows that PSEG, in support of the subsidy request, [redacted] of adjustments to the Hope Creek 1 operating costs that PSEG had submitted to EUCG for 2017. Assuming the same adjustment is made for each year, the inclusion of these adjustments to EUCG costs [redacted] over the three year period 2019-2021.

Table 29 PSEG adjusted O&M costs as provided to EUCG: Hope Creek 1

[redacted]

Table 30 and Table 31 show that PSEG, in support of the subsidy request, [redacted] to the Salem 1 operating costs and [redacted] to the Salem 2 operating costs that PSEG had submitted to EUCG for 2017. Assuming that same adjustment is made for each year, the inclusion of these adjustments to the EUCG costs [redacted] Salem 1 and Salem 2 by [redacted] for each unit over the three year period 2019-2021.

Table 30 PSEG adjusted O&M costs as provided to EUCG: Salem 1

[redacted]

Table 31 PSEG adjusted O&M costs as provided to EUCG: Salem 2

[redacted]

Non-Avoidable Overhead Costs

Under Operation & Maintenance, the line item in PSEG's claimed costs, "Support Services & Overhead" includes costs that would remain even if the unit shut down. PSEG provided a breakdown of non-avoidable overhead costs. [redacted]

Since these costs would be incurred even if the units shut down, they are not relevant to the decision to shut down the unit and ratepayers should not be asked to pay a subsidy to cover these costs. [redacted]

PSEG's inclusion of Non-Avoidable O&M costs increases Hope Creek 1 O&M costs by [redacted] million over the period 2019-2021, as shown in Table 32.

Table 32 Non-avoidable overhead costs 2019-2021: Hope Creek 1

[redacted]

PSEG's inclusion of Non-Avoidable O&M costs increases Salem 1 O&M costs by [redacted] million over the period 2019–2021, as shown in Table 33.

Table 33 Non-avoidable overhead costs 2019-2021: Salem 1

[redacted]

PSEG's inclusion of Non-Avoidable O&M costs increases Salem 2 O&M costs by [redacted] million over the period 2019–2021, as shown in Table 34.

Table 34 Non-avoidable overhead costs 2019-2021: Salem 2

[redacted]

Impact on PJM Fuel Diversity

The IMM analyzed the impact of Hope Creek 1, Salem 1 and Salem 2 on the fuel diversity of the PJM market. Figure 1 shows the fuel diversity index (FDI$_e$) for all PJM energy generation.[27] The FDI$_e$ is defined as $1 - \sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI$_e$ is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI$_e$ results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9.[28] The monthly average FDI$_e$ for 2018 was [redacted] an increase of [redacted] over the monthly average FDI$_e$ for 2017.

The FDI$_e$ was used to measure the impact on fuel diversity if Hope Creek 1, Salem 1 and Salem 2 were to retire, under two scenarios. In the first scenario, the generation from these nuclear units during 2018 was removed from the generation totals used to compute the FDI$_e$. The result was a [redacted] increase in the average FDI$_e$ for 2018, a slight increase in fuel diversity. In the second scenario, the nuclear generation was replaced by gas generation. The result was a [redacted] decrease in the average FDI$_e$

27 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

28 The ten fuel types used in the calculation of FDI$_e$ are biofuel, coal, energy storage, gas, hydro, nuclear, oil, solar, solid waste, and wind.

for 2018, a slight decrease in fuel diversity. The dashed green line and the black dotted line in Figure 1 show these two scenarios.

Figure 1 Fuel diversity index for monthly generation: June 2000 through December 2018

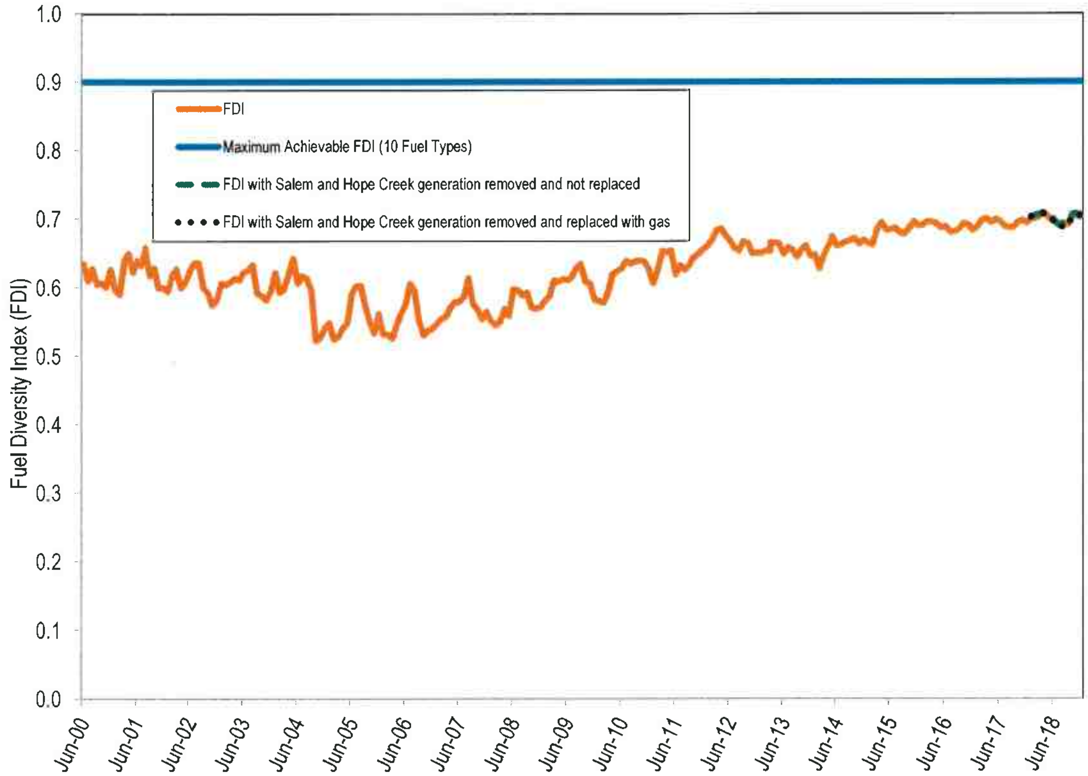

Figure 2 shows the fuel diversity index (FDI_c) for installed capacity. The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875.[29] The monthly average FDI_c for 2018 was [redacted] a decrease of [redacted] percent from the 2017 monthly average. Figure 2 includes the expected FDI_c through June 2021 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 2 by the dashed orange line.

The FDI_c was used to measure the impact on installed capacity if Hope Creek 1, Salem 1 and Salem 2 were to retire, under two scenarios. In the first scenario, the capacity from

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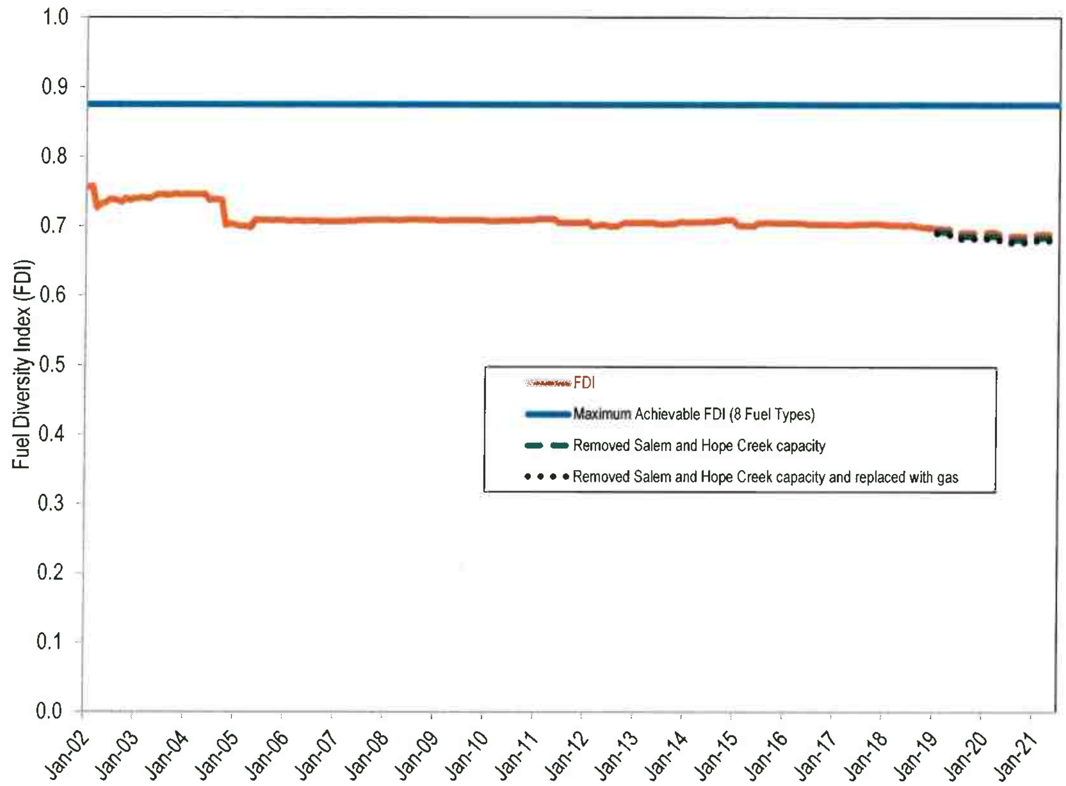
[29] The eight fuel types used in the calculation of FDI_c are coal, gas, hydro, nuclear, oil, solar, solid waste, and wind.

these nuclear units was removed from the expected FDI_c calculations for 2019 through June 2021. The result was a [redacted] decrease in the FDI_c, a decrease in diversity. In the second scenario, the nuclear capacity was replaced by gas capacity. The result was a [redacted] decrease in the FDI_c for 2018, a decrease in fuel diversity. The dashed green line and the black dotted line in Figure 2 depict these two scenarios.

Figure 2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



Details of Exelon Filing

Table 35 and Table 36 show the details of Exelon's ZEC submission in support of subsidies for Salem 1 and Salem 2. Starting from the left, the table shows all costs submitted by Exelon for their [redacted] share of the unit. Exelon costs are then grossed up to show equivalent Exelon costs for 100 percent of the Salem 1 and 2 units to facilitate comparison with PSEG costs for the entire units. The IMM adjustments are the same in this table as in prior tables.

The IMM analysis in Table 35 and Table 36 includes adjustments for [redacted] The IMM analysis using data from Exelon shows that Salem 1 revenues exceed its avoidable costs by [redacted] million over the three year period 2019-2021. The IMM analysis using data from Exelon shows that Salem 2 covers its going forward costs by [redacted] million over the three year period 2019-2021.

Exelon's costs are within rounding error of PSEG's costs [redacted] Using data from PSEG, the IMM analysis shows that Salem 1 covers its going forward costs by [redacted] million over the three year period 2019-2021 as shown in Table 3 and that Salem 2 covers its going forward costs by [redacted] million over the three year period 2019-2021 as shown in Table 4.

Table 35 Line item detail based on Exelon provided data: Salem 1

	Exelon Projection @ 42.59%	Exelon Projection @ 100%	IMM Analysis @ Exelon 100%
[redacted]			

Table 36 Line item detail based on Exelon provided data: Salem 2

[redacted]			