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February 12, 2021

Via Electronic Delivery
Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: I/M/O the Application of PSEG Nuclear, LLC and Exelon Generation Company, LLC for the Zero Emission Program – Salem Unit 1
I/M/O the Application of PSEG Nuclear, LLC and Exelon Generation Company, LLC for the Zero Emission Program – Salem Unit 2
I/M/O the Application of PSEG Nuclear, LLC for the Zero Emission Program – Hope Creek
BPU Docket Nos. ER20080557, ER20080558, & ER20080559

Dear Secretary Camacho-Welch,

My name is Frank Huntowski and I am a partner of the NorthBridge Group. NorthBridge is a consulting firm that provides economic and strategic advice to the electric and natural gas industries. I have been actively involved in the ZEC process here in New Jersey and provided oral comments in the February 1, 2021 public hearing in this matter. I was also involved in the proceedings to establish and implement the ZEC programs in New York and Illinois.

I am submitting these comments in response the New Jersey Board of Public Utilities' ("Board") January 15, 2021 notice in the above-captioned matter. The notice solicited public comments on the application the Salem 1 & 2 and Hope Creek nuclear units to receive Zero Emission Certificates ("ZECs") for the second eligibility period. NorthBridge commends the Board for taking the necessary steps to preserve New Jersey's nuclear assets, which continue to be the most economic source of carbon-free energy. I am providing these comments on the need for continuing support for nuclear generation in New Jersey and the appropriate level for the ZEC payment for the second eligibility period. I have three primary comments:

- Merchant nuclear plants throughout the country are in financial distress and most plants cannot survive without a payment for their carbon-free energy
- It is uneconomic for a nuclear plant owner to continue to operate a plant without adequate compensation for risk
- Current market conditions and benchmarks for reducing the ZEC level in other states suggest that the ZEC level in New Jersey should not be reduced at this time.

The remainder of these comments is structured around these three conclusions.

A. Merchant nuclear plants throughout the country are currently financially distressed

The actions taken by owners of merchant nuclear plants across the country over the past five years provide clear evidence of widespread ongoing financial distress. Figure 1 shows the recent actions taken by nuclear plants in the Midwest and Northeast (which contain the vast majority of the nation's merchant nuclear plants) with respect to either retirement or seeking sources of support, such as ZECs, to avoid retirement.

More than three quarters of merchant nuclear plants throughout the Northeast and Midwest have signaled financial distress through their actions – either a) retiring or announcing retirement, b) receiving state support to stave off retirement, or c) publicly announcing that they are financially distressed and will likely retire absent a material change. The financial challenges that have led the New Jersey nuclear plants to seek continued support in the form of the ZEC program are a reflection of the broad state of the industry and are both ongoing and widespread.

Figure 1: Merchant Nuclear Plants in Midwest and Northeast

Merchant Nuclear Plants in Midwest and Northeast			
Plant Name	**Location**	**MW**	**Current Status**
Oyster Creek	PJM (NJ)	637	Retired 2018
TMI	PJM (PA)	803	Retired 2019
Pilgrim	ISONE (MA)	679	Retired 2019
Indian Point 2	NYISO	1,018	Retired 2020
Byron 1-2	PJM (IL)	2,300	Scheduled for retirement
Dresden 2-3	PJM (IL)	1,797	Scheduled for retirement
Indian Point 3	NYISO	1,012	Scheduled for retirement
Quad Cities	PJM (IL)	1,819	Receiving ZECs – would have retired w/o ZECs
Salem 1-2	PJM (NJ)	2,328	Receiving ZECs – would have retired w/o ZECs
Hope Creek	PJM (NJ)	1,172	Receiving ZECs – would have retired w/o ZECs
Davis Besse	PJM (OH)	894	Would have retired w/o ZECs
Perry	PJM (OH)	1,240	Would have retired w/o ZECs
Millstone	ISONE (CT)	2,073	Receiving state support (CT) based on demonstrated need
Fitzpatrick	NYISO	851	Receiving ZECs – would have retired w/o ZECs
Ginna	NYISO	582	Receiving ZECs – would have retired w/o ZECs
Nine Mile 1-2	NYISO	1,916	Receiving ZECs – would have retired w/o ZECs
Braidwood 1-2	PJM (IL)	2,337	Economically distressed (public announcement)
LaSalle 1-2	PJM (IL)	2,265	Economically distressed (public announcement)
Calvert Cliffs 1-2	PJM (MD)	1,708	Financially challenged (filed comments in MD)
Beaver Valley 1-2	PJM (PA)	1,808	Scheduled retirement reversed due to PA RGGI
Limerick 1-2	PJM (PA)	2,242	Operating
Peach Bottom 2-3	PJM (PA)	2,451	Operating
Susquehanna 1-2	PJM (PA)	2,496	Operating
Seabrook	ISONE (NH)	1,250	Operating - partially contracted with CT

Financial distress at merchant nuclear plants is primarily due to the confluence of very low prices in electricity markets coupled with the lack of any compensation in those markets for the carbon-free attributes of the energy provided by nuclear generation. Market prices have declined due to a variety of factors. Most importantly, prices for natural gas, which is the most frequent marginal price-setting fuel in electricity markets as well as the primary fuel of choice for new entrant fossil generation, have declined by over 65% over the past 12 years, from a high of $7.40 per mmbtu on average over the 2004 to 2008 period to about $2.56 per mmbtu on average in 2019.[1] In addition, in many regions, new entry by zero marginal cost renewables which receive compensation for their positive environmental externalities outside of electricity markets through state renewable standards and/or federal tax credits has also put downward pressure on market prices. With a few very limited exceptions, however, markets themselves do not provide any

[1] Prices are for Henry Hub spot delivery.

compensation for the positive environmental externalities that nuclear provides as a carbon-free generation resource. Without such compensation, market prices on their own are simply too low to cover the costs and risks of operating a nuclear plant. In instances where states have stepped in and provided payment for the positive environmental attributes of nuclear via ZEC programs or similar support programs, financially challenged plants have been able to avoid retirement. When such compensation has not been available, the plants have retired.

B. It is uneconomic to operate a nuclear plant without sufficient compensation for cost and risk

Some parties in this proceeding have suggested that compensation for risk is not necessary to avoid nuclear retirements. This suggestion is not correct; risk is a critical and substantial component of the overall costs of owning and operating a nuclear plant, and failure to adequately compensate a plant for risk will result in that plant's retirement. It is uneconomic for an owner to keep a nuclear plant open if the plant just breaks even in good years and loses a significant amount of money in a bad year.

The need to compensate for risk, or provide a "risk premium," is a basic and widely accepted principle in financial economics, and it is applicable here. The ZEC level must be high enough so that a nuclear owner can cover the risks of keeping a plant open. As a simple analogy, consider the premium we all pay to insurance companies. Thankfully, I did not get into a car accident last year and I do not expect to get into one this year. But if based on that likelihood, I tried to obtain car insurance for free, there is no insurance company that would take on that risk without adequate compensation. Similarly, nuclear owners cannot be expected to take on the risks of operating a nuclear plant without adequate compensation.

Merchant nuclear plants, in particular, have very significant downside risk driven due to both operational and market risk components. For example, if a plant has an extended maintenance-related outage, it will receive no energy revenues or ZEC payments during that outage, will have to cover the price difference between spot market purchases and any forward sales, and will be subject to capacity performance penalties. Nevertheless, the plant will still need to continue to pay almost all operating costs during that time and pay additional costs to repair the cause of the outage. The existence of this large downside risk, which can be avoided by retiring the plant, increases the overall level of payment needed to retain and continue to operate the plant.

The projected cash flow excluding risk for a nuclear plant does not account for the huge variation in potential actual outcomes, especially towards the downside. The overall financial risk distribution is the aggregate result of several individual risk factors associated with operating a nuclear plant. In general, these risk factors can be divided into two broad categories: operational risk and market risk. Intuitively, operational risk results from the fact that operation of a nuclear plant is subject to uncertainties (for example, there could be outages, unexpected costs, etc.), while market risk results from the fact that the output of the plant is sold into electricity markets where prices are uncertain and volatile. Both of these risk factors can be further sub-divided into individual components, all of which must be understood and quantified in order to adequately compensate the plant owner for the risk of operating the plant.

Operational risks can be divided into two categories: operating cost risk and capacity factor risk.

Operating cost risk. Nuclear facilities face operating cost risk because many of the costs incurred in operation of a nuclear plant are not fully fixed and may be higher than projections. For example, an equipment failure at a plant may result in unanticipated replacement and repair costs, changing regulatory mandates may require unanticipated capital expenditures and/or increased staffing costs, and disruptions in uranium commodity and fuel processing/fabrication markets may result in increased fuel costs. Compared to other types of power generation, this risk is particularly pronounced for nuclear plants because they are subject to stringent oversight and can face additional, unforeseen regulatory requirements at any time. Recent real-world examples of the sorts of unforeseen costs that drive operating cost risk include the capital upgrades required of most U.S. nuclear plants stemming from the review of the Fukushima Daichi disaster in Japan, which resulted in approximately $4 billion of unexpected plant upgrade costs nation-wide (about $40 million per unit on average),[2] and a recent proposal (not ultimately realized) to add a domestic uranium purchase quota for U.S. nuclear plants which I estimated would have added between $1 and $2/MWh to nuclear fuel costs.[3] In addition to industry-wide cost increases, individual plants may face significant unexpected costs and other operational difficulties.

Capacity factor risk: nuclear facilities face capacity factor risk because their costs are largely fixed — that is, they remain largely the same even if plant output declines. As a result, lower than expected output (that is, a lower-than-expected capacity factor) results in an increase in costs per MWh of output. Moreover, while nuclear facilities generally are highly reliable and operate at extremely high capacity factors, when a nuclear outage does occur, it tends to be prolonged and the resulting increase in cost per MWh of output will thus be substantial. The cost increase related to a reduced capacity factor is proportional to the reduction in output. Specifically,

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[2] Nuclear Energy Institute, "Upgrades to Backup Safety Systems: Part of Fukushima Response," Fact Sheet February 2016. https://www.nei.org/resources/fact-sheets/upgrades-backup-safety-systems-fukushima-response

[3] Aaron Patterson and Frank Huntowski, "The Market Impact of Proposed Uranium Quotas on the U.S. Nuclear Power Industry," July 2018. https://www.nei.org/resources/reports-briefs/market-impact-proposed-uranium-import-quotas

all else equal, actual realized costs per MWh equal projected costs multiplied by 1 / (1 – reduction in capacity factor). For example, if a facility's projected costs are $100 million and projected output is 2.5 million MWh, this translates to a cost of $40/MWh ($100 million / 2.5 million MWh). If instead, that facility's output is reduced by 10% to 2.25 million MWh, then costs become $44.44/MWh ($100 million / 2.25 million). So, given a 10% reduction in output, actual realized costs per MWh turn out to be 11.1% higher than projected. Since the expected capacity factor of nuclear plants is very high, the ability to operate at higher levels (and lower per MWh costs) is limited.

To help quantify the capacity factor risk component, I analyzed publicly available data on annual industry-wide unit-level nuclear capacity factors for the approximately 100 nuclear units in the country from 2008 to 2019. This data is provided in Figure . A typical risk management practice when pricing risks that produce significant losses at low probabilities—such as capacity factor risks—is to set the cost of self-insurance at the fifth percentile level of the outcome distribution. That is, the effective self-insurance premium is set at a level that provides 95% confidence that the unit will not incur a loss due to a risk. Figure 2 shows that the fifth percentile capacity factor in each year has been on average about 18.6 percent below the industry wide average capacity factor. In other words, each year, there is a 5 percent probability that forced outages for a given facility will result in a capacity factor approximately 18.6 percent or more below the expected capacity factor—equivalent to a 23 percent increase in operating costs per MWh of production. Seen in this light, a 10 percent multiplier for operational risk is reasonable in that it is a) less than half this value, and b) intended to include operating cost risk as well, which is not quantified in this simple analysis.

Figure 2: Nuclear Capacity Factors, 2008 to 2019

Unit Capacity Factor by Year	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Source for Capacity Factor Data: U.S. Nuclear Regulatory Commission Information Digests (NUREG 1350)												
A: Mean Capacity Factor	92%	91%	88%	89%	88%	92%	86%	86%	89%	91%	91%	92%
B: 5th Percentile Capacity Factor	79%	79%	73%	72%	76%	81%	62%	55%	69%	76%	72%	82%
C: Unexpected Generation Deviation (= 1 - B/A)	14%	14%	17%	19%	13%	12%	28%	36%	22%	17%	20%	11%
2008 to 2019 Average Unexpected Generation Deviation	18.6%											
Individual Unit Capacity Factors:												
Arkansas Nuclear One, Unit 1	87%	76%	87%	72%	82%	98%	56%	102%	87%	90%	99%	83%
Arkansas Nuclear One, Unit 2	82%	82%	70%	94%	89%	85%	91%	93%	90%	97%	90%	91%
Beaver Valley Power Station, Unit 1	91%	92%	99%	91%	90%	86%	86%	92%	101%	91%	92%	101%
Beaver Valley Power Station, Unit 2	100%	90%	90%	97%	90%	98%	97%	91%	102%	84%	87%	103%
Braidwood Station, Unit 1	94%	93%	98%	90%	93%	103%	95%	91%	101%	89%	95%	101%
Braidwood Station, Unit 2	100%	92%	88%	95%	91%	96%	98%	93%	93%	99%	93%	92%
Browns Ferry Nuclear Plant, Unit 1	99%	82%	97%	83%	94%	90%	94%	88%	91%	86%	94%	88%
Browns Ferry Nuclear Plant, Unit 2	80%	97%	83%	94%	85%	98%	79%	99%	80%	91%	94%	98%
Browns Ferry Nuclear Plant, Unit 3	94%	76%	93%	80%	92%	88%	89%	83%	87%	81%	95%	81%
Brunswick Steam Electric Plant, Unit 1	92%	85%	93%	83%	93%	89%	92%	77%	100%	83%	98%	85%
Brunswick Steam Electric Plant, Unit 2	85%	93%	82%	92%	81%	98%	73%	98%	79%	99%	80%	95%
Byron Station, Unit 1	100%	94%	89%	97%	88%	97%	96%	88%	88%	101%	94%	95%
Byron Station, Unit 2	95%	100%	89%	86%	94%	94%	86%	94%	93%	96%	102%	96%
Callaway Plant	86%	100%	77%	87%	96%	89%	77%	103%	90%	86%	98%	90%
Calvert Cliffs Nuclear Power Plant, Unit 1	100%	92%	97%	89%	97%	91%	97%	81%	101%	90%	98%	93%
Calvert Cliffs Nuclear Power Plant, Unit 2	92%	100%	91%	95%	86%	100%	81%	101%	92%	97%	93%	99%
Catawba Nuclear Station, Unit 1	100%	93%	90%	97%	88%	86%	96%	89%	89%	100%	91%	89%
Catawba Nuclear Station, Unit 2	92%	91%	96%	88%	86%	100%	86%	92%	101%	92%	90%	103%
Clinton Power Station, Unit 1	87%	88%	84%	89%	87%	97%	82%	100%	93%	92%	97%	99%
Columbia Generating Station	88%	96%	77%	92%	78%	98%	80%	97%	50%	95%	67%	93%
Comanche Peak Nuclear Power Plant, Unit 1	89%	100%	91%	92%	100%	85%	94%	98%	91%	91%	100%	96%
Comanche Peak Nuclear Power Plant, Unit 2	94%	93%	68%	100%	88%	93%	99%	91%	92%	104%	94%	95%
Cooper Nuclear Station	100%	81%	99%	84%	97%	88%	97%	87%	86%	100%	72%	90%
Davis-Besse Nuclear Power Station, Unit 1	98%	93%	97%	79%	97%	74%	95%	91%	81%	66%	99%	97%
Diablo Canyon Nuclear Power Plant, Unit 1	89%	98%	81%	98%	87%	87%	95%	84%	100%	88%	84%	98%
Diablo Canyon Nuclear Power Plant, Unit 2	75%	87%	95%	88%	95%	86%	82%	97%	89%	100%	84%	74%
Donald C. Cook Nuclear Plant, Unit 1	79%	100%	72%	82%	78%	94%	78%	104%	87%	88%	3%	64%
Donald C. Cook Nuclear Plant, Unit 2	84%	79%	104%	71%	79%	101%	85%	91%	104%	84%	87%	101%
Dresden Nuclear Power Station, Unit 2	89%	99%	84%	91%	83%	98%	85%	104%	95%	102%	91%	98%
Dresden Nuclear Power Station, Unit 3	99%	94%	91%	84%	89%	95%	89%	91%	99%	90%	97%	93%
Duane Arnold Energy Center	99%	93%	88%	79%	88%	79%	89%	83%	99%	89%	92%	103%
Edwin I. Hatch Nuclear Plant, Unit 1	98%	91%	97%	93%	101%	89%	94%	89%	98%	85%	94%	84%
Edwin I. Hatch Nuclear Plant, Unit 2	82%	95%	95%	101%	91%	99%	89%	98%	78%	96%	67%	96%
Fermi, Unit 2	99%	75%	82%	86%	69%	82%	62%	54%	94%	80%	75%	98%
Grand Gulf Nuclear Station, Unit 1	88%	57%	58%	47%	93%	82%	86%	70%	94%	88%	100%	86%
H. B. Robinson Steam Electric Plant, Unit 2	94%	79%	88%	95%	85%	86%	85%	85%	100%	57%	104%	87%
Hope Creek Generating Station, Unit 1	84%	90%	94%	85%	83%	102%	80%	93%	103%	93%	95%	108%
Indian Point Nuclear Generating, Unit 3	91%	92%	78%	102%	86%	98%	94%	100%	90%	99%	85%	107%
James A. FitzPatrick Nuclear Power Plant	100%	89%	80%	76%	96%	79%	89%	84%	97%	85%	99%	89%
Joseph M. Farley Nuclear Plant, Unit 1	91%	84%	100%	86%	86%	102%	90%	91%	101%	88%	90%	97%
Joseph M. Farley Nuclear Plant, Unit 2	92%	99%	91%	90%	98%	89%	91%	104%	89%	88%	96%	90%
LaSalle County Station, Unit 1	99%	92%	96%	89%	99%	93%	95%	97%	101%	94%	99%	100%
LaSalle County Station, Unit 2	92%	98%	88%	95%	83%	95%	88%	103%	96%	101%	93%	94%
Limerick Generating Station, Unit 1	99%	92%	100%	93%	100%	91%	101%	85%	96%	91%	101%	95%
Limerick Generating Station, Unit 2	91%	99%	86%	101%	89%	99%	94%	95%	90%	99%	94%	101%
McGuire Nuclear Station, Unit 1	90%	100%	90%	89%	95%	82%	82%	105%	94%	92%	104%	87%
McGuire Nuclear Station, Unit 2	100%	92%	86%	97%	87%	94%	95%	82%	91%	104%	94%	90%
Millstone Power Station, Unit 2	97%	82%	85%	93%	85%	85%	95%	83%	87%	97%	81%	86%
Millstone Power Station, Unit 3	89%	100%	89%	83%	97%	87%	87%	100%	87%	86%	105%	88%
Monticello Nuclear Generating Plant, Unit 1	88%	99%	86%	93%	78%	78%	50%	101%	69%	94%	83%	97%
Nine Mile Point Nuclear Station, Unit 1	85%	99%	87%	96%	88%	98%	88%	87%	84%	97%	92%	98%
Nine Mile Point Nuclear Station, Unit 2	99%	90%	101%	92%	100%	87%	99%	83%	95%	89%	99%	90%
North Anna Power Station, Unit 1	93%	90%	99%	89%	91%	100%	89%	89%	78%	86%	92%	101%
North Anna Power Station, Unit 2	88%	99%	89%	87%	99%	92%	85%	99%	76%	100%	100%	82%
Oconee Nuclear Station, Unit 1	100%	90%	95%	83%	96%	91%	91%	90%	79%	100%	85%	84%
Oconee Nuclear Station, Unit 2	90%	100%	88%	98%	89%	101%	82%	102%	93%	91%	103%	86%
Oconee Nuclear Station, Unit 3	100%	92%	97%	91%	97%	92%	97%	86%	103%	91%	94%	102%
Palisades Nuclear Plant	97%	77%	86%	99%	89%	86%	85%	74%	96%	92%	90%	99%
Palo Verde Nuclear Generating Station, Unit 1	90%	97%	85%	83%	94%	90%	85%	100%	83%	81%	101%	86%
Palo Verde Nuclear Generating Station, Unit 2	98%	82%	86%	95%	85%	90%	91%	90%	91%	101%	83%	74%
Palo Verde Nuclear Generating Station, Unit 3	87%	90%	92%	85%	85%	101%	79%	88%	97%	89%	83%	97%
Peach Bottom Atomic Power Station, Unit 2	100%	94%	92%	96%	99%	88%	100%	88%	101%	92%	102%	89%
Peach Bottom Atomic Power Station, Unit 3	93%	94%	86%	95%	75%	103%	85%	103%	90%	100%	89%	99%
Perry Nuclear Power Plant, Unit 1	83%	99%	85%	91%	83%	96%	73%	92%	79%	98%	67%	98%
Point Beach Nuclear Plant, Unit 1	91%	99%	86%	86%	92%	90%	84%	100%	79%	88%	98%	87%
Point Beach Nuclear Plant, Unit 2	99%	94%	85%	94%	86%	90%	93%	89%	67%	96%	84%	89%
Prairie Island Nuclear Generating Plant, Unit 1	99%	89%	88%	81%	77%	84%	90%	81%	91%	96%	97%	84%
Prairie Island Nuclear Generating Plant, Unit 2	91%	100%	80%	78%	65%	101%	59%	74%	99%	86%	75%	85%
Quad Cities Nuclear Power Station, Unit 1	91%	99%	85%	92%	83%	103%	85%	102%	92%	99%	82%	96%
Quad Cities Nuclear Power Station, Unit 2	99%	92%	89%	85%	95%	90%	91%	92%	104%	92%	91%	86%
R.E. Ginna Nuclear Power Plant	99%	93%	87%	94%	89%	91%	93%	90%	84%	97%	91%	109%
River Bend Station, Unit 1	76%	82%	77%	78%	76%	96%	84%	91%	90%	98%	113%	82%
St. Lucie Plant, Unit 1	70%	91%	90%	73%	83%	101%	74%	72%	85%	72%	100%	91%
St. Lucie Plant, Unit 2	100%	87%	84%	92%	77%	82%	91%	68%	66%	100%	80%	99%
Salem Nuclear Generating Station, Unit 1	79%	100%	90%	68%	95%	86%	88%	97%	86%	85%	99%	91%
Salem Nuclear Generating Station, Unit 2	99%	87%	85%	85%	85%	73%	100%	88%	89%	98%	93%	83%
Seabrook Station, Unit 1	100%	92%	92%	99%	87%	93%	100%	75%	77%	100%	81%	89%
Sequoyah Nuclear Plant, Unit 1	82%	89%	88%	71%	87%	100%	83%	89%	98%	84%	89%	101%
Sequoyah Nuclear Plant, Unit 2	99%	88%	83%	90%	73%	90%	90%	77%	89%	97%	89%	89%
Shearon Harris Nuclear Power Plant, Unit 1	89%	89%	99%	90%	87%	99%	83%	90%	103%	90%	94%	99%
South Texas Project, Unit 1	100%	89%	85%	95%	78%	81%	91%	93%	94%	101%	90%	95%
South Texas Project, Unit 2	91%	90%	97%	88%	85%	103%	59%	72%	88%	88%	101%	95%
Surry Power Station, Unit 1	88%	87%	101%	96%	76%	99%	91%	92%	101%	89%	94%	98%
Surry Power Station, Unit 2	100%	88%	93%	101%	82%	95%	101%	91%	76%	100%	92%	94%
Susquehanna Steam Electric Station, Unit 1	99%	86%	97%	77%	76%	83%	87%	70%	86%	80%	101%	89%
Susquehanna Steam Electric Station, Unit 2	89%	99%	86%	93%	82%	88%	80%	83%	72%	96%	90%	100%
Turkey Point Nuclear Generating Unit No. 3	99%	89%	80%	93%	78%	84%	81%	40%	96%	88%	86%	101%
Turkey Point Nuclear Generating Unit No. 4	91%	100%	98%	99%	106%	88%	70%	85%	84%	98%	99%	89%
Virgil C. Summer Nuclear Station, Unit 1	95%	85%	77%	96%	79%	81%	93%	86%	88%	100%	81%	87%
Vogtle Electric Generating Plant, Unit 1	100%	93%	93%	101%	91%	87%	101%	91%	92%	102%	91%	93%
Vogtle Electric Generating Plant, Unit 2	92%	100%	96%	94%	100%	92%	87%	102%	94%	93%	101%	88%
Waterford Steam Electric Station, Unit 3	74%	100%	80%	96%	80%	90%	89%	77%	82%	100%	87%	89%
Watts Bar Nuclear Plant, Unit 1	86%	87%	77%	85%	76%	89%	90%	87%	84%	99%	94%	82%
Wolf Creek Generating Station, Unit 1	87%	86%	96%	74%	78%	83%	65%	80%	72%	86%	86%	83%
Fort Calhoun Station, Unit 1						100%	1%	0%	28%	102%	100%	83%
Indian Point Nuclear Generating, Unit 2		90%	73%	53%	77%	93%	77%	90%	98%	82%	98%	91%
Oyster Creek Nuclear Generating Station			113%	95%	109%	90%	106%	88%	98%	85%	92%	83%
Pilgrim Nuclear Power Station			86%	92%	85%	97%	74%	98%	85%	99%	90%	97%
Three Mile Island Nuclear Station, Unit 1		100%	80%	82%	77%	104%	78%	100%	92%	94%	86%	107%
Watts Bar Nuclear Plant, Unit 2	88%	95%	45%									
Vermont Yankee							93%	92%	90%	88%	99%	89%
Crystal River Nuclear Generating Plant, Unit 3								0%	0%	0%	95%	95%
Kewaunee Power Station									93%	102%	93%	90%
San Onofre Nuclear Generating Station, Unit 2								0%	105%	75%	60%	91%
San Onofre Nuclear Generating Station, Unit 3								0%	104%	69%	94%	72%

While the likelihood of a given unit suffering a large drop in capacity factor in a given year is not necessarily large, for most nuclear units, this risk has materialized at some point. Over the last decade, about 60 of the roughly 100 nuclear units across the U.S. have suffered a year in which outages caused the plant to run 10 percent or more below the typical level for a nuclear plant. These two types of operational risk—operating cost risk and capacity factor risk—tend to be realized together which amplifies their impact on the overall financial risk level for a given plant. For example, if an unexpected equipment failure takes a facility offline, the facility will face the unanticipated cost of repairing the equipment failure and its costs will be spread over fewer megawatt-hours of output than anticipated.

Market risks arise from the fact that merchant nuclear facilities sell their energy and capacity output into electricity markets where prices are not fixed but rather are determined by supply and demand as they vary over time and, as a result, the actual revenues realized by a nuclear facility may fall below projected revenues. Nuclear facilities do attempt to hedge market risks using forward markets and other risk management tools, but not all market risks can be hedged and in other cases the cost of hedging itself is high enough that self-insurance is economically preferable. Market risk can be sub-divided into three categories: liquidated damages risk, volatility risk, and basis risk. While the details of each category vary, they all stem from instances where a nuclear plant cannot easily or cost-effectively hedge a particular risk associated with selling power into volatile electricity markets.

Liquidated damages risk. To hedge against volatile market prices, nuclear facilities typically sell forward their energy production during all hours at a specified fixed price using a widely traded forward contract structure known as a liquidated damages contract. The projected market energy revenues for the nuclear plants effectively assume such a forward sale because they are based on these forward contract prices. A liquidated damages contract specifies that the seller must deliver energy at the contractual delivery point at all times over the contract term regardless of whether or not the physical assets used by the seller are available. Thus, if the seller's facility experiences an unexpected forced outage, the owner will need to cover its forward obligation by purchasing replacement energy from the spot market. Liquidated damages risk is the risk that a facility experiencing an outage will need to procure replacement electricity from the spot market at prices in excess of its forward sale price. Spot market prices during an unexpected nuclear outage can be much higher than usual, because the forced outage of a large baseload unit will require reliance on higher priced units to fill the gap. The cost associated with covering a forward obligation by purchasing from the spot market at elevated prices is the cost imposed by liquidated damages risk.

While power plant owners typically measure and price liquidated damages risk using proprietary probabilistic models, there is some market evidence available that suggests it is quite substantial. Liquidated damages risk can be estimated by examining the price difference between liquidated damages contracts and "unit contingent" contracts for the same location and time period. Unit contingent contracts avoid the risk associated with liquidated damages contracts by only requiring delivery of energy while the facility linked to the contract is available. All published benchmarks of standardized forward energy products are liquidated damages products, but unit contingent products do trade periodically in bilateral markets. Because selling liquidated damages energy is significantly riskier that unit contingent energy, liquidated damages contracts require a higher price than unit contingent contracts. While there is relatively little data on this liquidated damages premium, I have been able to gather data from two sources that suggests that liquidated damages risk is quite material for nuclear facilities. First, Entergy Corporation, the then-owner of two nuclear plants in New York, has provided information to the investment analyst community indicating that it generally accepted a $3.5 per MWh discount on power sold from its New York nuclear facilities on a unit contingent basis relative to power sold on a liquidated damages basis.[4] Second, Exelon Corporation indicated in its comments to PJM's initial Capacity Performance proposal in late 2014 that it had extensive experience with unit contingent products at that the typically traded at a $1.5 to $4 per MWh discount to similarly-situated liquidated damages products.[5]

Another component of this type of risk that is additional to the estimates discussed above is the risk of incurring capacity performance penalties during an outage. If a nuclear outage results in a performance assessment interval, the lost production from the forced-out unit will be assessed performance charges of approximately $3,000 per MWh (depending on the zone in which the plant is located). Like the liquidated damage risk associated with energy, this type of risk cannot be hedged and is potentially quite material.

Volatility risk. Volatility risk is the risk that a nuclear facility will not actually be able to achieve its projected revenues due to volatility in market prices. While nuclear facilities are able to hedge a portion of market price volatility risk using forward markets, due to constraints on liquidity they are typically not able to hedge all of their expected output over multiple years forward without driving down forward prices, and must thus typically delay a portion of their forward sales until closer to the delivery year, or even sell a portion of their output unhedged in the spot market. As a result, nuclear facilities cannot always obtain in practice the forward prices

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[4] Entergy Corporation Presentation, "EWC Value Story, 2014 Analyst Day," June 5, 2014, Slides 5-6.
[5] Comments of Exelon Corporation on PJM's Capacity Performance Proposal, Submitted to the PJM Capacity Performance Enhanced Liaison Committee, Sept 17, 2014, at 15.

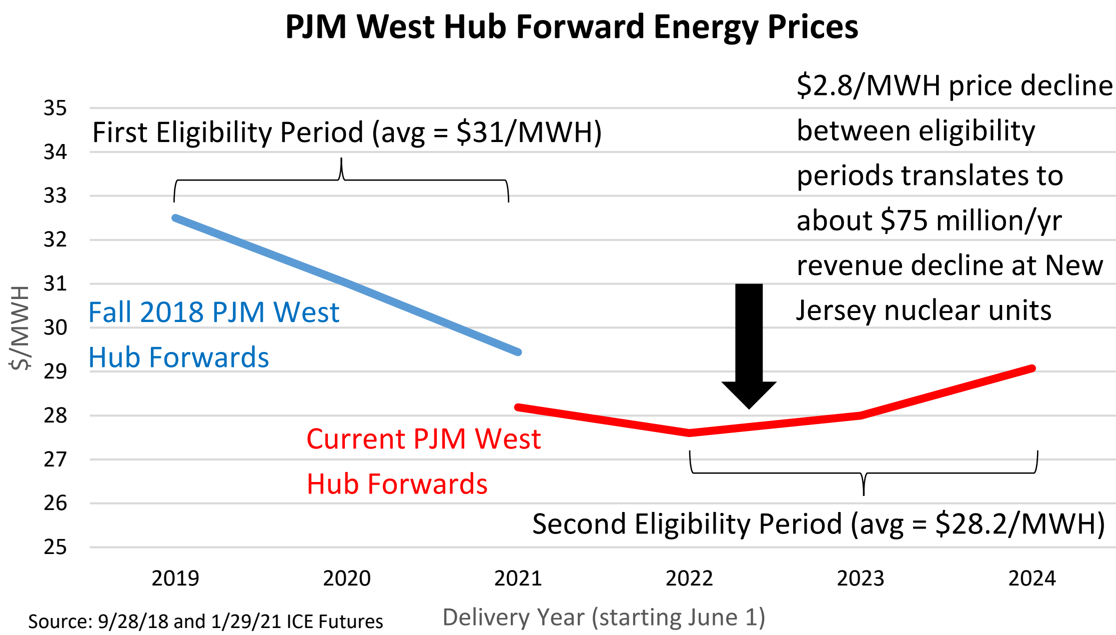
assumed by revenue projections and instead are exposed to price volatility on a portion of their expected output.

Basis risk. Basis is the amount by which energy prices at the particular node where a plant sells its output diverge from the liquid hubs at which forward prices are delivered. The energy price projection used to set projected revenues typically includes an adjustment for the expected difference between the hub-level and plant-level energy price (this difference is known as the "plant basis") based on historical energy spot price data. However, basis risk arises because of the possibility that the actual plant basis over a given year will diverge from the expected plant basis and thus the plant would sustain an incremental loss if the actual plant-level basis was lower than expected. The risk of such divergence is difficult to hedge in forward markets. Plant basis risk is additional to the volatility risk, which measures the risk associated with volatility in forward prices at the forward delivery point.

C. Current market conditions and benchmarks for reducing the ZEC in other states suggest that the ZEC level in New Jersey should not be reduced at this time

As part of this second ZEC application process, some commentors have noted that forward energy market prices increased during the second half of 2020. While this is true, current forward market prices are still roughly 9% lower than prices at the time of the first ZEC application in the fall of 2018. As shown in in Figure 3, PJM West Hub forward prices for the three years covering the first ZEC eligibility period were about $31 per MWh on average. As of now, forward prices over the second eligibility period (2022 – 2024) are $28.2 per MWh, or about $2.8 per MWh below average forward prices for the first eligibility period as of fall 2018.

Figure 3



The energy prices shown are for the PJM Western Hub, a liquid trading hub. The New Jersey plants receive the nodal prices at their individual interconnection points, which have historically reflected a considerable discount to the Western Hub. Over the past three years (2018 to 2020), the average nodal price at the NJ nuclear plants has been about $3.8 per MWh below the Western Hub price. If this discount continues, the future energy price received by the New Jersey plants for the second eligibility period will be below $25 per MWh. Based on these current market conditions then, over the second eligibility period the New Jersey plants can expect to realize revenues of approximately $75 million per year (or $2.8 per MWh) below the level that was expected at the inception of the first eligibility period in fall 2018. This means that, without recognition of the value of carbon-free energy, these units would lose $75 million per year more than they would have based on the market conditions from a few years ago.

This type of market price comparison – between current market prices and a price benchmark set at the time the ZEC was first established – is how both the New York and Illinois

ZEC programs determine whether their ZEC levels should be reduced. These programs include a provision whereby the ZEC level is reduced if market conditions improve from the time that ZECs were established. The ZEC level in both New York and Illinois exceeds the $10/MWh payment provided for under the New Jersey ZEC law. For the ZEC level to be reduced in those states, market prices would have to be higher than when the ZECs were established. But the opposite has occurred. Market prices have fallen since 2016 when ZECs were established in New York and Illinois. As shown above, they have also fallen appreciably since the initial ZEC applications were filed in New Jersey in 2018. So, current market conditions and benchmarks for reducing the ZEC level in other states suggest that the ZEC level in New Jersey should not be reduced at this time.

Thank you for the opportunity to provide these comments.

Sincerely,

/s/ Frank Huntowski
Frank Huntowski, Partner

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