Salem 1 - Cost of Market Risks

1. Introduction

The following provides an overview of the methodology utilized by PSEG to assess the cost of market risks avoided by ceasing operations. Market risks are risks associated with the uncertainty of revenues, as opposed to operational risks, which are associated with the uncertainty of costs. The legislation specifies 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*[1]," which highlights that market risks can be broken down into two fundamental categories: forced outage risk and price volatility risk.

The first category of market risks, forced outage risk, reflects the risk that actual generation will fall short of forecasted generation due to higher than anticipated forced outages, resulting in lower than expected revenues and/or a mismatch between previously contracted sales and actual generation. As a result, the generation owner will have to "cover" its contracted sales during outages by purchasing energy in the spot market at prices potentially much higher than the contracted price or *hedged* price.

The second category of market risks, price volatility risk, reflects the risk that the forecasted energy output and capacity from the nuclear power plant may not be able to be sold at projected prices. For energy output, this risk arises from the fact that there is limited liquidity for nuclear generators seeking to sell large volumes at forward prices at the generation bus, especially

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[1] N.J.S.A. 48:3-87.5 (a)

[redacted]

for longer dated tenors, and that the spot price at delivery at the generation bus has the potential to vary dramatically from the current forward price at the market trading hub. Additionally, because PJM has yet to hold Base Residual Auctions (BRA) for capacity for energy years 2022/2023 through 2024/2025, capacity revenues remain uncertain and may vary from PSEG's forecast.

PSEG estimates the total overall cost of market risks, including both forced outage risk, and energy and capacity price volatility risk, taking into account the mitigating effects of PSEG Power's hedging practice, to be $[redacted]/MWh for Salem 1 ("the Unit"). The following sections provide further detail regarding the calculation of these market risks.

2. Methodology and Model Overview for Energy Market Risks

To assess market risk, PSEG utilizes a well-known energy risk modeling software application, [redacted]. This software application allows PSEG to evaluate the probabilistic distribution of future energy market revenues based on a joint simulation of generating unit outages and energy market prices. To assess the cost of market risks, PSEG used the same software application, inputs, and modeling approach that PSEG uses in the ordinary course of business to assess market risk for PSEG Power's entire portfolio of merchant generation and hedges.

As described in more detail in sections below, the inputs to PSEG's energy market risk model are based on forward curve and volatility data from [redacted], historical spot price data from PJM ISO, PSEG Power's established energy hedging practice, PSEG Power's current hedge positions, unit-specific outage forecast, and historical forced outage variability.

[redacted]

PSEG's practice is to assess and manage portfolio market risk at the 95% confidence level which is consistent with portfolio risk limits specified in PSEG's Financial Risk Management Practice, a practice that is periodically reviewed and approved by PSEG's Board of Directors. Similarly, PSEG discloses to investors information regarding the Value-at-Risk of its Mark-to-Market derivative positions at both the 95% and 99.5% confidence levels in its quarterly and annual reports[3], consistent with instructions from the Securities and Exchange Commission, which directs that "*[t]he confidence intervals selected should reflect reasonably possible near-term changes in market rates and prices. In this regard, absent economic justification for the selection of different confidence intervals, registrants should use intervals that are 95 percent or higher*[4]." The assessment of the cost of market risks included in this application reflects PSEG's normal business practice to manage its portfolio market risk at the 95% confidence level, i.e. the 5th percentile downside. The use of the 95% confidence level in this application is also consistent with the 95% confidence level used by Constellation Energy Nuclear Group, LLC (CENG) for its calculation of the cost of market risks in its New York ZEC program application[5].

3. Forced Outage Risk

Forced outage risk is the risk that a facility experiencing an outage will need to procure replacement electricity, either physically or financially, and may be required to do so at prices in

[3] PSEG Form 10-Q filed for quarter ending June 30, 2020 (pdf page 103, shown as page 90 in the document) http://d18rn0p25nwr6d.cloudfront.net/CIK-0000788784/13219019-d69c-4051-9b9b-45dc0c65c028.pdf

[4] Securities and Exchange Commission, § 229.305, Instructions to paragraph 305(a), Instruction 4.A https://www.gpo.gov/fdsys/pkg/CFR-2010-title17-vol2/pdf/CFR-2010-title17-vol2-sec229-305.pdf

[5] Comments of Constellation Energy Nuclear Group, LLC ("CENG") Concerning [New York Public Service Commission] Staff White Paper on Clean Energy Standard. Pages 6, 24, 25, 26, and 27. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={805D1362-DE4F-46D6-9BD4-7E0C8C65341E}

excess of its LD forward sale price. In order to hedge against volatile energy market prices, owners of nuclear generation facilities typically sell forward energy contracts at a specified fixed price. The projected energy market revenues in this submission effectively assume such forward sales because they are based on futures prices that are for "liquidated damage" or "LD" energy delivery during all hours regardless of plant operations. Therefore, if the facility experiences a forced outage, the owner will need to cover its LD forward obligation by purchasing replacement energy from the spot market. 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 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 the cost imposed by forced outage risk.

To model this exposure arising from uncertainty around generation forced outages, PSEG jointly simulates generation outages along with prices to arrive at an annual distribution of forced outage risk. PSEG ensures that the average outage rate in its market risk model is consistent with the business plan expected forced outage rates and that the simulated outage rate uncertainty around the expected forced outage rate is consistent with the historical outage distribution. The chart below (Fig. 1) depicts the results of this analysis for the Unit under current market conditions. The horizontal axis of the chart measures the annualized cost or benefit to the unit of needing to cover a forced outage in the spot energy market, assuming the unit is 100% hedged, spread over the unit's planned annual output. A negative value indicates a loss and a positive value indicates a gain. The y-axis of the chart measures the cumulative probability that the unit experiences a particular level of loss or gain. The fifth percentile downside level for annual forced outage risk is a loss of $3.1/MWh (red "X" marker on the chart). Thus, consistent with PSEG's normal business practices, the self-insurance cost of forced outage risk should be set at this level. As the chart depicts, however, in the extreme tail of the distribution the potential loss could approach \$6/MWh, which would mean PSEG could still lose as much as \$2/MWh or more in excess of the self-insurance amount of \$3.1/MWh.

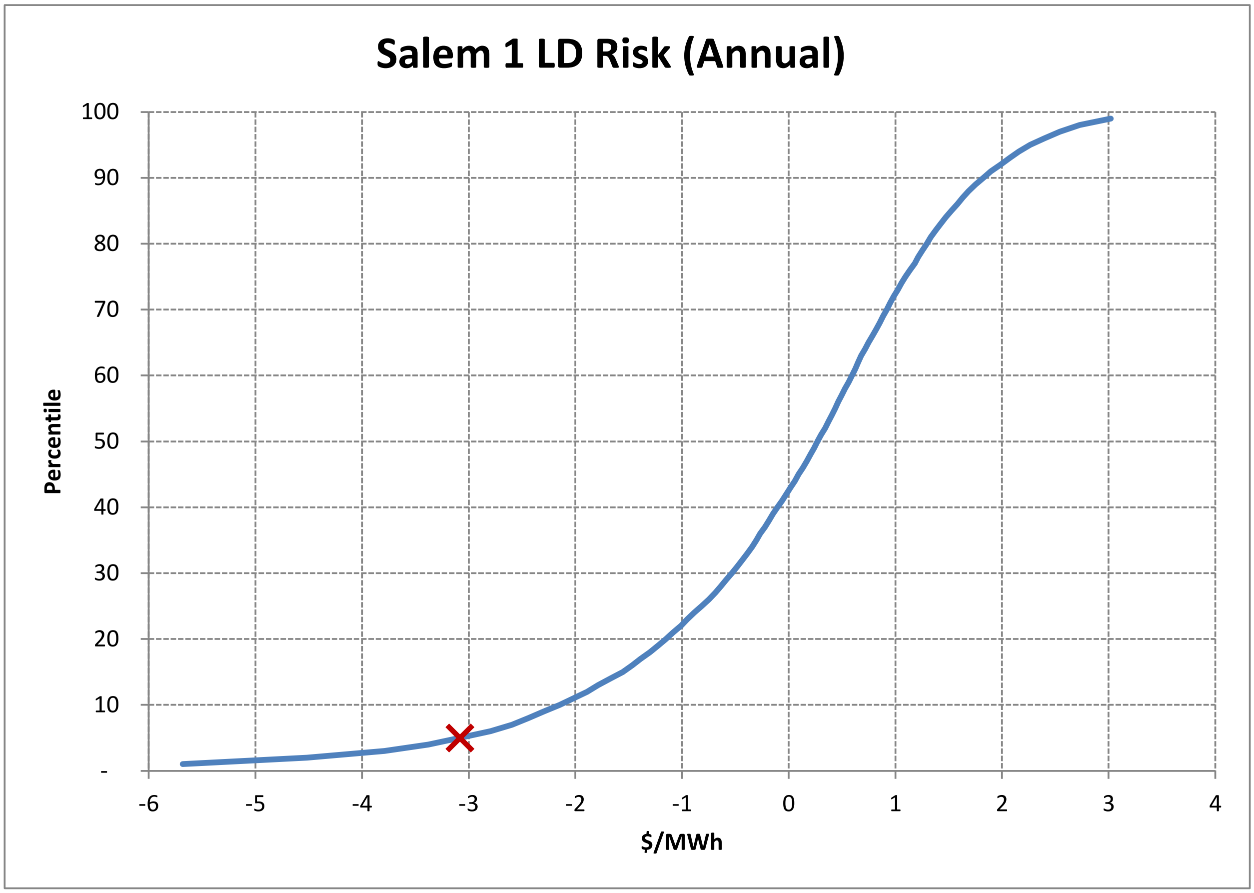

Fig. 1

There is some diversification benefit when this annual forced outage risk is analyzed over a three-year period (energy planning years 2022/2023 through 2024/2025). When accounting for the diversification of forced outage risk across the three-year period, the 5th percentile downside risk of loss is \$1.7/MWh, and the 1st percentile downside risk of loss can approach \$2.8/MWh.

It is appropriate to include the cost associated with self-insurance against forced outage risk in the assessment of a facility's costs, because owners of nuclear generation facilities must take on this risk in order to receive the LD energy prices, the futures prices, reflected in this submission.

The cost of forced outage or "LD risk" should be considered jointly with the cost of price volatility risk while also taking into account the risk mitigated by PSEG Power's hedging practice. These additional impacts are detailed in the following sections.

4. Energy Price Volatility Risk

1.1. Overview

Although owners of nuclear generation facilities typically sell forward energy contracts to reduce the uncertainty of revenues in upcoming years, hedge contracts are an imperfect mechanism for a particular plant to lock in an expected price level. First, due to the large volume that needs to be sold forward, not all of the plant output can be sold at one time at the current forward energy price. Second, the most commonly traded forward contracts are for a hub energy price, which is the average price of many locations across multiple states, rather than the price at the specific plant location.

In PJM ISO, the ISO in which the Unit operates, a generator receives the LMP (locational marginal price) associated with its respective generation bus for the energy it produces. This price reflects the "clearing" price of the particular ISO node needed to balance supply and demand across all ISO nodes after having taken into account transmission system congestion. The LMP of a particular generation bus changes every hour and its average value can vary significantly from month to month and year to year. The LMP represents the electricity spot price, and the energy price volatility risk is the risk that the actual LMP realized for the delivery period will deviate from current forward expectations.

A commodity forward contract is an agreement to sell (or purchase) an agreed upon quantity of a commodity at a specified price to be delivered at a specific location at some future date. In the case of electricity forward contracts, the underlying commodity against which the forward contract is written is the electricity spot price - or LMP. For this reason, the forward price of electricity is understood in energy markets to reflect the market's expectation of the spot price for the future period to which the forward contract corresponds. The active presence of both sellers and buyers in the forward market and the convergence of forward prices and LMPs at delivery imply that forward prices must reflect current expectations regarding spot prices for the future delivery period underlying the forward price.

In the electricity markets for PJM, the most liquid and commonly traded contracts are associated with the PJM Western Hub. The Western Hub is the average price of a collection of PJM nodes across Pennsylvania, Maryland and the District of Columbia, which collectively form the price for the PJM Western Hub. The price of the PJM Western Hub can deviate significantly from the price at the Unit. While it is possible, over time, to contract for large quantities of forward energy at the PJM Western Hub price, contracts for products that are more strongly correlated with the Unit are more limited in liquidity.

From a forward traded product or hedging instrument perspective, the LMP at a generator bus can be thought of as the sum of three components: a "hub" price, the "zone-to-hub basis" price, and a "bus-to-zone" price differential, or basis, as shown below in Figure 2. This decomposition is helpful for two reasons. First, these components are the building blocks for which forward hedging instruments may be partially available and therefore are the building blocks with which the expectation of the future LMP at the generating bus can be built. Second, since PSEG Power will be adding hedges for both "hub," "zone-to-hub basis" and, in part, for "bus-to-zone basis" in different quantities at different times in the future, the model needs to include an explicit projection of the forward prices of these building blocks at various points in the future. The overall price volatility risk is the risk that the price at which the nuclear plant output is actually sold, taking hedges into account, will deviate from expectations.

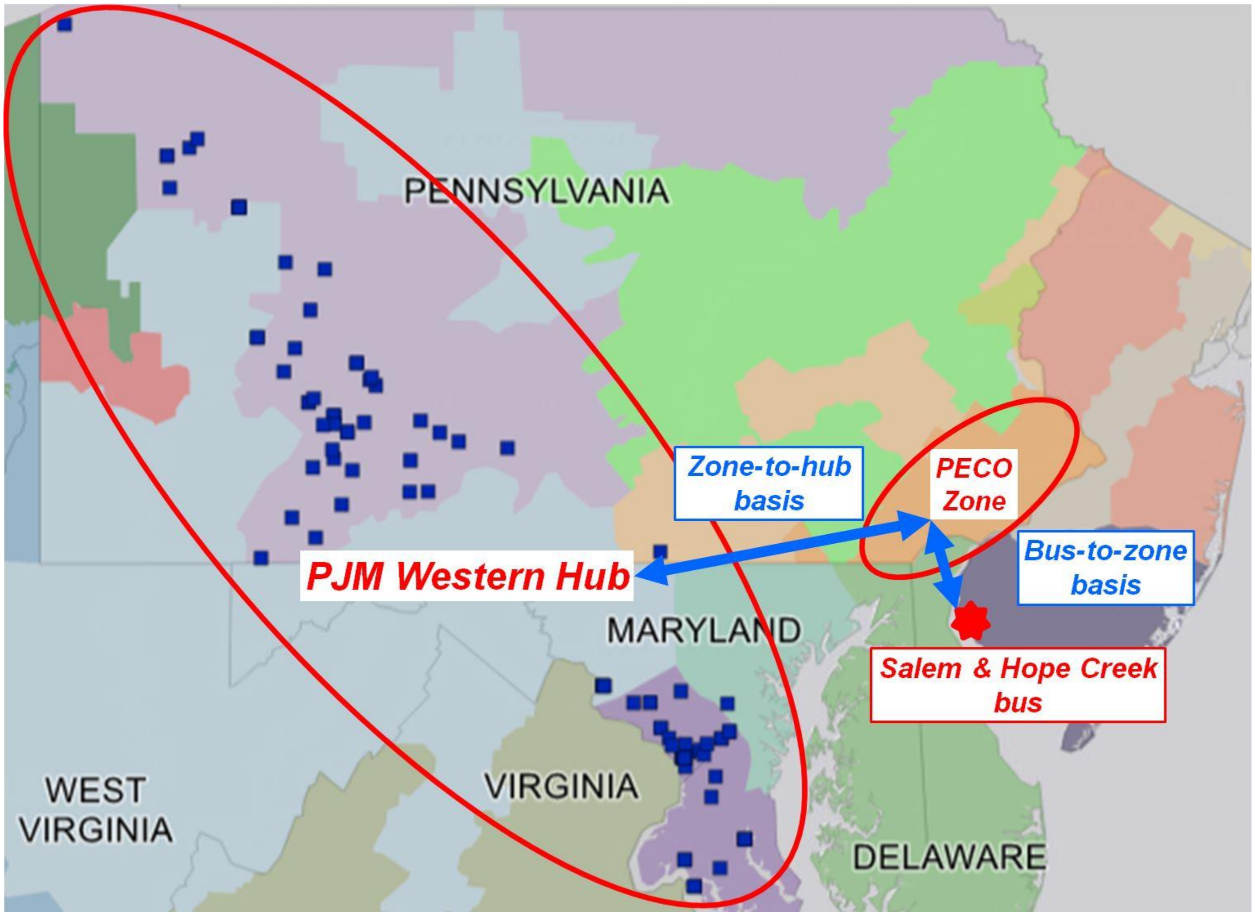

Fig. 2 (Illustrative. Colored areas represent zones, including PECO example. Blue dots illustrate PJM Western Hub nodes)

1.1. Hub Price Volatility

On commodity exchanges such as the ICE, NYMEX, and Nodal Exchange, the PJM Western Hub is the underlying price index for various financial derivatives – swaps and options. The prices of exchange-traded swaps for the PJM Western Hub represent what is commonly referred to as the "forward curve" for PJM West, representing the market expectation of future prices for various maturities, or underlying periods.

While the swap prices - or forward curve – represent today's expectation of future spot prices for a particular future period, there remains uncertainty as to what the actual spot price will be. In other words, the swap price simply reflects the price that a market participant is willing to pay or receive today for a future underlying period. At delivery, the spot price will inevitably vary from the current forward price. This uncertainty is commonly referred to as market price volatility. The PJM Western Hub price volatility can be inferred from the prices of swaptions (options on swaps) traded against an underlying PJM Western Hub swap. The benefit of this approach, commonly known as option "implied volatility," is that it can be interpreted to be the market's independent consensus on expectations regarding volatility.

PSEG's market risk volatility model for the PJM Western Hub is calibrated to the implied volatility observed in the commodity swap and option markets. In order to achieve this, PSEG begins by first modeling forward curve dynamics based on historical forward and spot price data. This part of the process is built upon a multi-factor forward curve model that is designed to incorporate both the volatility term structure and seasonality observed in energy markets. The model is then calibrated such that the distribution of potential terminal forward prices aligns with the distribution of potential prices resulting from the market's expectations regarding price uncertainty - the option *implied* volatility. Comparisons between PSEG's modeled forward price stress and a price stress based on [redacted] implied volatility[6] as of May 29, 2020 are shown

[redacted]

below in Figures 3 and 4, for PJM Western Hub calendar forward prices and monthly forward prices respectively. The proximity of PSEG's modeled forward price stress (solid green and red lines) to the price stress based on option market implied volatility (dashed green and dashed red lines) is evidence that the model is well calibrated to volatility observed in the traded options market.

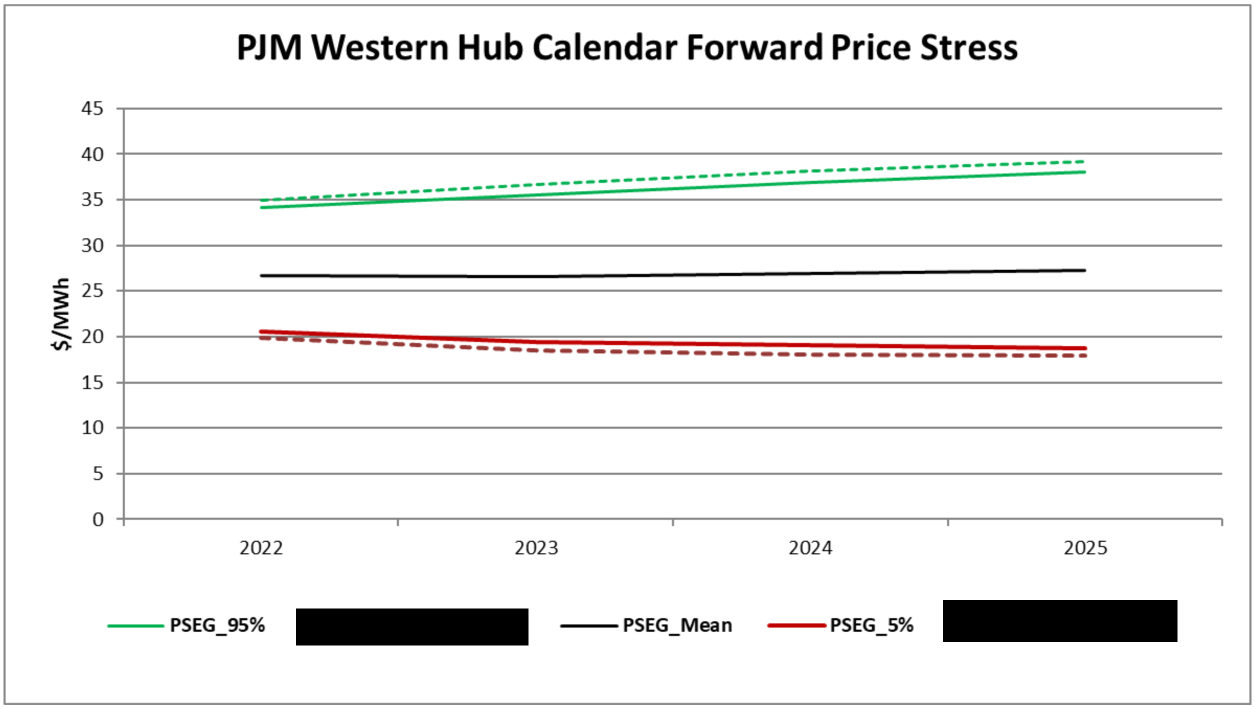

Fig. 3

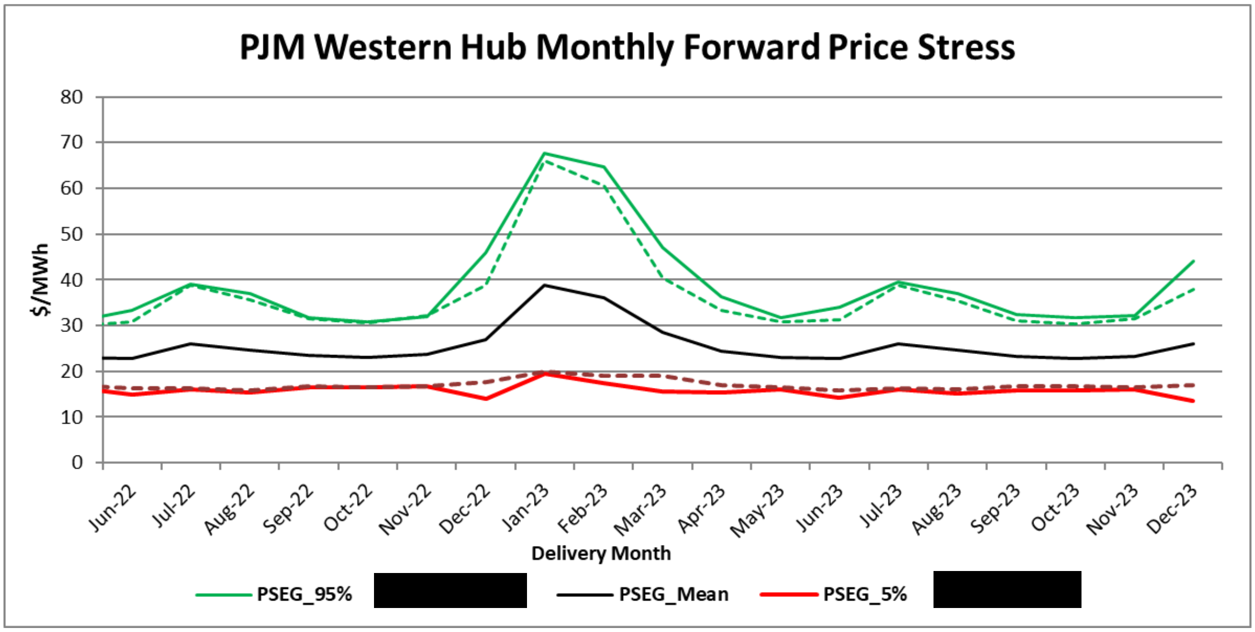

Fig. 4

1.2. Price Volatility: Zonal Power Basis & Bus-to-Zone

Similar to risk associated with the hub energy price, a generator is also exposed to zonal basis price risk. Zonal basis is defined as the spread between the energy price at a given ISO zone and the price at an ISO hub. For example the PECO zonal basis is the difference between the energy price at the PJM PECO Zone and the price at the PJM Western Hub. Forward prices for zonal basis are observable on Nodal Exchange, ICE, and NYMEX. However, unlike for the PJM Western Hub, there is no observable option market for zonal power basis. Therefore, PSEG builds its zonal power basis volatility assumptions using historical basis price data and distributions. The same approach is also used to model the volatility of the "bus-to-zone" price (the spread between the price at the generation bus and the PECO zone).

1.3. Correlation and Resulting Bus Price Volatility

The model aggregates the risks of potential adverse price movements on the PJM Western Hub, PECO zonal power basis, and bus-to-zone basis, by taking into account the correlation among these three sources of risk, which PSEG calculates based upon historical energy price data. This is done in order to achieve simulated results with a risk diversification among the three price volatility exposures that is consistent with historical data. Specifically, from a standalone perspective, the 5th percentile downside stress is \$7.4/MWh on the PJM Western Hub, \$3.0/MWh on the PJM PECO Zonal basis, and \$0.9/MWh on the “bus-to-zone” basis between the Unit and the PECO zone. By comparison, the 5th percentile downside stress on the absolute bus price for the Unit is \$9.0/MWh (unhedged).

This market price stress of \$9.0/MWh, assuming no hedges, represents a potential downside movement from the time of this ZEC application forward and is equal to approximately 38% of the forward price expectation for the Unit’s bus of \$23.8/MWh for the period of June 2022 – May 2025 used in this market risk assessment. As a point of comparison, the chart below (Figure 5) depicts the historical realized changes between forward price expectations and realized LMPs (assuming a lead time of twenty months) at the Unit’s bus for consecutive three year periods, dating back to the three-year period of 2005-2007. For example, the data point of negative 37% for 2016-2018 reflects that the realized LMP for the three-year strip of 2016-2018 was 37% lower than the forward expectation as observed on April 30, 2014. As illustrated by the chart, a 38% decrease between current forward expectations and realized LMPs is within the range of historical outcomes, and price movements of this magnitude have materialized on multiple occasions.

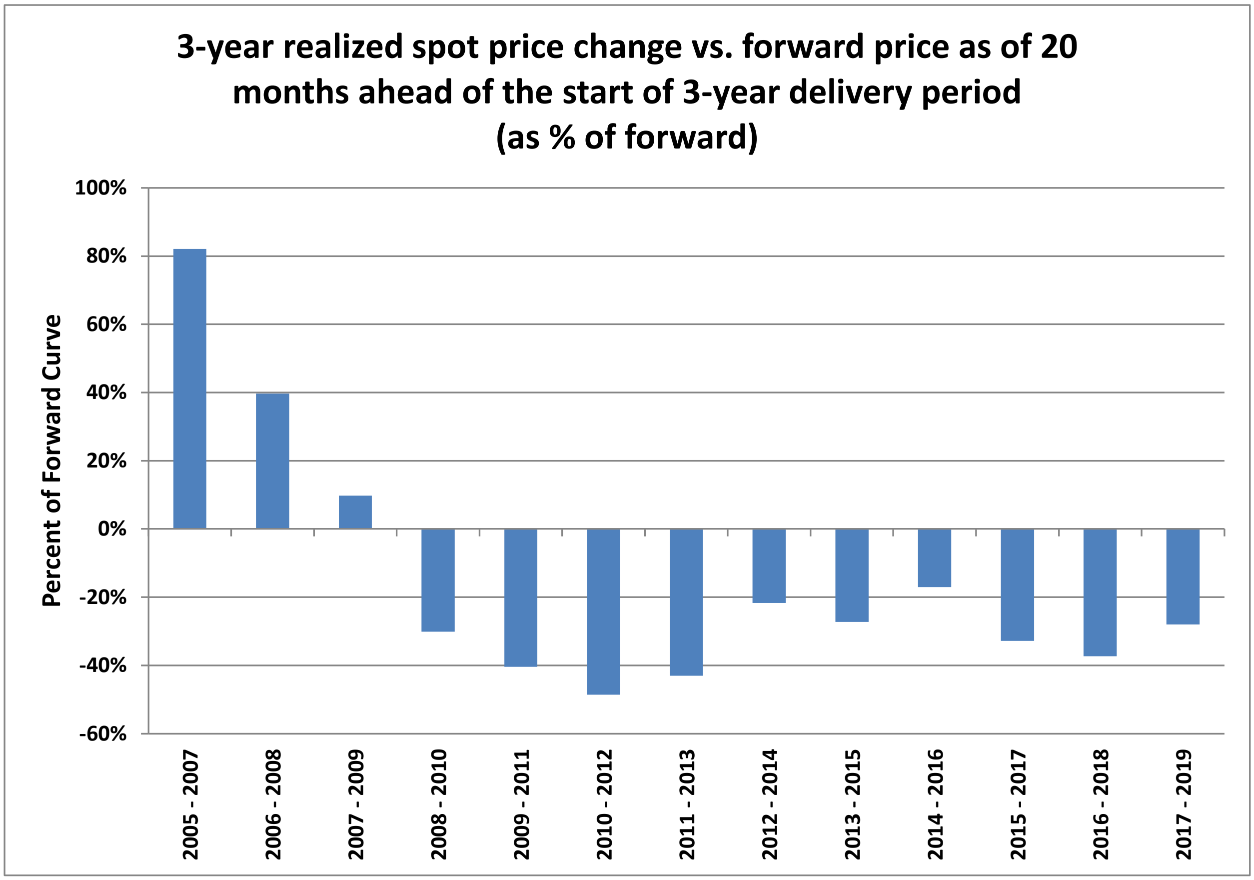

Fig. 5

5. Hedging

5.1. Hedging Practice Overview

PSEG Power employs a hedging program in order to mitigate its exposure to energy market price volatility. The hedging practice is designed to gradually add hedges over a specific term preceding the delivery period of the underlying exposure. Gradually hedging in this way allows for dollar cost averaging of energy sales and mitigates exposure to energy market price volatility.

Below are details on the structure, timing and amount of hedging assumed in the calculation of the cost of energy market risk, based on PSEG's hedging practice and available market liquidity.

5.2. PJM Western Hub Hedging

For the PJM Western Hub, PSEG Power gradually hedges its exposure over a preceding three-year term such that by the time a delivery year is reached, 100% of the PJM Western Hub component of the generators' bus price exposure is hedged[7]. For example, for the delivery period of calendar year 2025, approximately one third of 2025 expected generation would be sold forward by the end of 2022, two thirds by the end of 2023, and 100% by the end of 2024. In this way, PSEG Power is able to hedge all of its Western Hub exposure in the forward market such that it is not exposed to Western Hub spot price volatility.

Because PJM Western Hub hedges are modeled as calendar swaps (flat volume for the whole calendar year), PSEG adds balancing swaps to its model to ensure that the volume of total PJM Western Hub hedges matches the monthly generation profile of the generating unit, thus accounting for planned outages.

The chart shown below in Figure 6 provides a graphical illustration of the amount of PJM Western Hub hedging for the calendar delivery year 2023. The dashed lines represent the minimum and maximum hedging targets from the PSEG hedging practice. The solid line represents the hedging path assumed for PJM Western Hub calendar year 2023 in the calculation of the cost of energy market risk.

[7] The PJM Western Hub component of the price exposure can be hedged with PJM Western Hub hedges or with zonal transactions that simultaneously hedge both the PJM Western Hub component and the "zone-to-hub basis" component.

[redacted]

Fig. 6

5.3. Zonal Basis Hedging

[redacted]

[redacted]

[redacted]

Fig. 7

5.4. Bus-to-Zone Hedging

[redacted] FTRs only hedge congestion - one of the two components of variability in bus-to-zone basis. The other component, locational marginal losses, cannot be hedged. In addition, FTRs also bear the risk of underfunding. For these two reasons, FTRs are an imperfect hedge for bus-to-zone price volatility risk. Further, FTRs are only available for specific delivery periods, at discrete auction dates in the year, and the quantity that can be hedged depends on the outcome of the auctions. As a result of these factors, the exact amount of future FTR hedging is hard to predict. [redacted]

5.5.Modeling of the Hedging Practice

In order to properly model the impact of PSEG Power's hedging practice, we first assume that PSEG will ratably hedge to the target hedging level from the level of hedges held as of May 29, 2020. PSEG models all future hedges anticipated by the hedging practice as forward starting swaps (sales). These swaps are modeled such that the sales price assumed to be received by PSEG Power is set at each specified hedging interval. For instance, if the hedging practice required PSEG Power to sell, in the month of March 2022, 100MW of PJM Western Hub power for the 2023 delivery period, PSEG's risk model would incorporate a forward starting swap for 2023 Western Hub power with an assumed forward sale price equal to the price simulated by the model for the 2023 delivery period as of the March 31, 2022 forward curve date. In this way, PSEG's risk model includes the price exposure experienced by PSEG Power for the period of time prior to the anticipated hedge, but reflects the risk mitigation of the hedge from that point onward through delivery. A similar approach is used to model zonal power basis hedges and FTRs.

6. Overall Cost of Energy Market Risks

The various drivers of energy market risk – market price volatility of PJM Western Hub prices, zonal power basis prices, and generator bus-to-zone basis prices, together with PSEG Power's hedging practice - are jointly simulated with forced outage risk in a manner consistent with correlations derived using historical data, ensuring that the resulting cost of market risks associated with forced outage risk and energy price volatility risk reflects historically appropriate diversification between various risk exposures. The cost of forced outage risk and energy price volatility risk at the 5th percentile downside is estimated to be $[redacted]/MWh. This is the diversified residual cost of energy market risks associated with forced outage risk and market price volatility after taking into account both currently existing hedges and the risk mitigation attributable to PSEG Power's hedging practice.

7. Capacity Price Risk

In addition to the energy price volatility risk outlined above, PSEG Power also bears capacity price risk for the Unit for the energy years 2022/2023 through 2024/2025 given that PJM has yet to hold capacity Base Residual Auctions (BRA) for these energy years. This risk was not material for the initial ZEC eligibility period because, at the time of the application for the initial ZEC eligibility period, the BRA's had already been held for energy years 2019/2020 – 2021/2022. PSEG faces two basic risks in relation to capacity: first, that the auction clearing prices for capacity for these years may differ negatively from PSEG's forecast and, second, that the implementation of the Minimum Offer Price (MOPR) rule by PJM may cause the Unit to not clear the capacity auction for one or more energy years.

The MOPR floor price for existing resources with a state subsidy has not yet been finalized by PJM and FERC, but is expected to be based on the Avoidable Cost Rate (ACR) for the resource or the default ACR value for the resource class. A forward looking energy and ancillary services (E&AS) offset is subtracted from this gross value to yield a net ACR. A larger E&AS offset will result in a lower MOPR floor price, which increases the likelihood that the resource will clear in the capacity auction. A lower E&AS offset will lead to a higher net ACR, which increases the risk that the generating unit may not clear in the BRA. The primary driver of the E&AS offset is the forward energy price for the planning year relevant to the BRA, as observed approximately 6 months prior to the auction. Given that nuclear units are heavily reliant on energy market revenues, changes in forward energy prices are expected to have a significant impact on a nuclear unit's MOPR floor price and thus its ability to clear in the BRA.

It should be noted that there are a number of additional variables which could impact the ability of the nuclear units to clear as well as the price at which the auction may clear. These risks include regulatory risk around finalization of the MOPR rules at FERC, changes in PJM capacity auction parameters, as well as the market risk of lower than expected auction clearing prices. PSEG focuses its analysis on the risk that the Unit does not clear the capacity auction as a result of the MOPR floor price, since this is potentially one of the most significant sources of risk associated with capacity revenues across the three New Jersey nuclear generating units. However, sources of capacity revenue uncertainty not reflected in this cost of market risk estimate could also be significant.

In modeling the MOPR risk, PSEG's analysis focuses on variations in the PJM Western Hub energy price because this is consistent with PJM ISO's proposed methodology of starting with the Hub[8] energy price, then adjusting to a zonal energy price (for a zone determined by PJM) based on the most recent FTR auction and historical marginal losses and, finally, adjusting the zonal price to the unit bus using historical congestion as a means of assessing the E&AS offset impact on the minimum offer price. PSEG did not reflect in the model the uncertainty stemming from the impact on the EA&S offset of any volatility of the zone-to-hub basis and bus-to-zone basis.

[8] PJM does not propose to lock a fixed set of trading hubs into the Tariff, but instead details the methodology in the manuals so that it can be adjusted as the energy markets evolve.

In order to model the risk that the Unit's MOPR floor may prevent it from clearing in one or more of the 2022/2023, 2023/2024, or 2024/2025 BRA's, PSEG has incorporated into its market risk model capacity revenue scenarios where the MOPR floor price impact for each iteration of the simulation is based upon the same PJM Western Hub forward prices used to estimate the energy market outcome for that iteration.

PSEG assumes that the EA&S offset for the 2022/2023 BRA auction will be calculated based upon the forward energy price for planning year 2022/2023 as of the middle of December of 2020. Following this, PSEG assumes that the EA&S for the 2023/2024 BRA will be based on 2023/2024 forward energy prices as of the middle of June 2021, and likewise that the EA&S for the 2024/2025 BRA will be based on 2024/2025 forward energy prices as of the middle of December of 2021.

[redacted]

In the joint simulation of the energy market risk and the portion of the Unit's capacity revenue risk modeled as described above, the capacity risk component adds $[redacted]/MWh to the overall cost of market risk of the unit. However, as noted above, the only portion of the Unit's capacity risk that is included in the model is the capacity revenue risk stemming from the MOPR floor price uncertainty associated with future PJM Western Hub prices. While PSEG estimates this is potentially one of the most significant sources of risk associated with capacity revenues, other sources of capacity revenue risk exist that are not included in this estimate, as noted above.

8. Overall Cost of Market Risks

PSEG's cost of energy market risk and cost of capacity price risk are jointly simulated in PSEG's risk modeling application. The result is an overall cost of market risks [redacted].