Analysis of Pennsylvania Nuclear Plants and Available Policy Alternatives

PREPARED BY:

Andrew G. Place
Commissioner, Pennsylvania Public Utility Commission

Hayley Book
Advisor to Pennsylvania Public Utility Commission Commissioner Andrew G. Place

Eric Matheson
Advisor to Pennsylvania Public Utility Commission Commissioner Andrew G. Place

March 6, 2019

The analysis herein is solely that of those preparing this report and does not reflect the position of any other Commissioner or of the Pennsylvania Public Utility Commission as a whole.

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Executive Summary

Pennsylvania has the second largest nuclear capacity of any state in the nation, with nine nuclear units, at five locations throughout the state. Exelon Generation, and FirstEnergy Corp, the respective owners of three of these units, Three Mile Island Unit-1 and Beaver Valley Units 1 and 2 have announced the premature retirement of these plants. Though PJM, the regional grid operator, indicates that the retirement of Beaver Valley and Three Mile Island will not impact the reliability of the electric grid, there may be additional infrastructure investments needed if Beaver Valley closes. Also, these nuclear plants represent a significant portion of Pennsylvania's carbon free generation, the loss of which would result in a backsliding of air quality in Pennsylvania. The question remains how to, or if at all to, intervene to prevent the premature closure of these two plants.

Experts agree that single unit reactors such as TMI are uneconomic, and industry and plant specific data validate this conclusion. However, the conclusions around the economics of Beaver Valley are less straightforward. Some studies indicate that Beaver Valley is economic, and that the closure of TMI may not necessarily be followed by additional nuclear power plant closures.

Nevertheless, though the extent of closures is debated, there is a substantive risk of the loss of some carbon free generation in Pennsylvania. This paper outlines the reasons for the energy transformation in Pennsylvania and offers market analysis and impacts of potential solutions.

- Pennsylvania nuclear generation plants provide 39% of PA's electricity generation. TMI and Beaver Valley account for 26% of this nuclear generation.
- Single-unit reactors, such as TMI, are at an economic disadvantage and will continue to be in the future.
- If TMI were to retire prematurely no new network transmission upgrades would be required. However, Beaver Valley, should it retire in 2021, will require an acceleration in an estimated $182 million in incremental transmission investments.
- PJM's recent analysis indicated that even with the announced retirements the PJM system is reliable today and will remain reliable into the future.
- If energy efficiency goals were increased by 1% of statewide usage per year, the lost emissions reductions for each plant could be replaced in 5 and 11 years, respectively.
- At the current annual rate of increase in Alternative Energy Portfolio Standard (AEPS) Act Tier 1 resources, it would take Pennsylvania 12.6 years to replace the lost carbon free electricity from TMI, and an additional 28.4 years to replace Beaver Valley.[1]

[1] The AEPS Act provides for an annual increase in clean Tier 1 resources of 0.5% of total Pennsylvania electricity consumption through 2021. Legislative amendments to the Act would be required to extend this annual increase post 2021.

Pennsylvania's Nuclear Fleet

Pennsylvania is the second largest nuclear capacity state in the nation, with 9 operating nuclear units, at 5 locations throughout the state, with a cumulative installed capacity (ICAP) of approximately 10.1 GW.[2] From a portfolio perspective, this represents 23% of Pennsylvania's generation capacity, and 39% of its electric generation.[3] Pennsylvania's nuclear unit information is as follows:

Unit Name	Operator	# Units	Location	County	ICAP, MW
Beaver Valley	FirstEnergy	2	Shippingport	Beaver	1,845
Limerick	Exelon	2	Limerick	Montgomery	2,326
Peach Bottom	Exelon	2	Peach Bottom	York	2,526
Susquehanna	Talen Energy	2	Salem	Luzerne	2,568
Three Mile Island	Exelon	1	Middletown	Dauphin	818

Of Pennsylvania's five nuclear plants, only 2 plants (3 units) in Pennsylvania have informed PJM of their intent to deactivate: Exelon's Three Mile Island (TMI) and FirstEnergy's Beaver Valley, which collectively account for 2.7 GWs, or 26% of Pennsylvania's nuclear capacity.

Some caveats are in order here with regard to the discussion below on individual plant economics. These cost and revenue estimates reflect system average operating and capital costs. Individual plants may be above or below industry average costs. However, the analysis by Monitoring Analytics (MA), PJM's Independent Market Monitor (IMM), does not reflect declining operating costs consistent with historical industry trends. Instead, the IMM assumes constant costs. Also, any individual plant could have a pending and significant capital expenditure that may alter its own situation relative to its peers in the short term.

Three Mile Island

Three Mile Island (TMI) entered commercial service in 1974 and Unit-1 is currently 100% owned by Exelon Nuclear. The adjacent Unit 2 — shut down in 1979 after the partial meltdown that put the brakes on the nation's nuclear program — is owned by FirstEnergy Corp. Final cleanup of the damaged Unit 2 reactor awaits the retirement of the surviving unit. In August of 2015 Exelon announced that TMI was among its plants that failed to clear the 2018-2019 Base Residual Auction (BRA), not qualifying for capacity payments from PJM (the regional transmission organization that operates the transmission grid) typically a relied upon revenue source for baseload generation. On May 30, 2017, PJM was notified by Exelon that it was going to deactivate the TMI nuclear power plant by September 30, 2019.[4] Subsequently, Exelon has indicated that it will deactivate this plant on schedule absent "needed policy reforms", with a final decision date of May 2019, due to critical refueling investments that are required to avoid full shutdown in September 2019.

[2] EIA Form 860, weighted average of summer and winter capacity ratings.
[3] 2017 Pennsylvania State Infrastructure Report, May 2018.
[4] Unit-1 is licensed by the U. S. Nuclear Energy Regulatory Commission to operate until 2034.

In several forums, Exelon has indicated that the TMI plant is uneconomic based on current PJM market prices. Further, TMI has not cleared in the last four BRAs in PJM's capacity market, thus losing a substantial and important revenue source to support its operations.[5]

TMI is a single-unit plant which is costlier to operate compared to the multi-unit sites. While statistics from the Nuclear Energy Institute indicate costs are 22 percent higher at single-unit plants, [6] an independent economic analysis performed by the IMM [7] indicated that it may be 38% more costly. Many of the reactors slated for early retirement nationwide are, likewise, single-unit plants. On May 24, 2017, Exelon disclosed that TMI has lost $300 million over the last five years[8].

The IMM's analysis of TMI in its October 2018 State of the Market Report, confirms that TMI is currently economically challenged. Single unit nuclear plants, without any pricing of their carbon free attribute, are not currently economic in PJM markets, and are projected to remain uneconomic for the next three years, even if they did procure a capacity commitment. Per the IMM's analysis, TMI lost approximately $100 million between 2012 and 2016, but that assumes TMI cleared the capacity auction every year. To the extent TMI did not clear the capacity auction, the losses would have been higher. IMM's analysis projected that losses will continue through 2021 at TMI, even if the plant did clear in the capacity auction, which it hasn't. Projected annual losses for TMI average $54 million per year with capacity revenues, and $86 million per year without capacity revenues.

Projected losses, however, are highly sensitive to energy prices in PJM. For example, in 2018, the *actual* average energy price for the year at the TMI pricing node (wholesale pricing location) was $31.76/MWh[9], relative to the projected TMI price of $31.36 used in the IMM analysis – very close to that projected by the IMM, but 17%, or $4.64/MWh, higher than in 2017, and $8.08**/**MWh higher than in 2016. Therefore, losses in 2016 and 2017 were much higher. Even so, if TMI had cleared the capacity market in 2018, it would still have lost $32 million. Having not cleared in the capacity market, however, estimated TMI losses were $73 million in 2018. Generally, every $1/MWh increase in wholesale energy prices increases generation revenues by $7 million.

Exelon will have additional refueling costs this year. A decision to shut down operations must be made by the end of May or beginning of June 2019, in order to avoid shut down in September 2019 as announced by the Company due to required advanced contracting and ordering of parts and labor.

Beaver Valley

Unit 1 and Unit 2 at Beaver Valley were commissioned for service on July 2, 1976 and November 17, 1987, respectively. On March 28, 2018, FirstEnergy Solutions Corporation (FES) announced that it

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[5] Exelon Press Release, May 24, 2018

[6] For the purposes of this analysis, operating costs were estimated at $30.89/MWh for a double unit plant, and $42.66/MWh for a single unit plant,

[7] http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q3-som-pjm-sec7.pdf, pages 327-332.

[8] https://www.philly.com/philly/business/energy/nuke17-headline-here-20170914.html.

[9] https://www.pjm.com/-/media/committees-groups/committees/mc/20190122-webinar/20190122-item-06a-markets-report.ashx, slide 3.

plans to retire its Perry and Davis-Besse plants in northern Ohio and the Beaver Valley plant located in Western Pennsylvania by 2021. On May 24, 2018 FirstEnergy confirmed that these three nuclear generation plants did not clear in the 2018 BRA in PJM's capacity market for the 2021-2022 delivery year.[10] On August 15, 2018, FES took its next step towards the closure of these nuclear power plants, filing plans related to their decommissioning with the U.S. Nuclear Regulatory Commission (NRC). Beaver Valley Power Station Unit 1 is licensed to operate until 2036 and Unit 2 is licensed through 2047. According to the NRC letter dated April 25, 2018, FES plans to close Unit 1 on May 31, 2021, and Unit 2 on October 31, 2021.[11]

Beaver Valley is a dual-unit plant. The IMM analysis does not demonstrate that the plant is uneconomic nor does it confirm a strong and sustained need for economic assistance. Market revenues dipped in 2012 and 2016, causing the plant to have a slight estimated operating loss in those two years. However, in all other years, and all projected years, Beaver Valley is projected to be profitable by the IMM. Projected average profits were $96 million per year, if the two units clear in the capacity market, and $23 million per year if they don't clear, for the 2018-2021 period. Using the actual Day Ahead average Locational Marginal Price (LMP) applicable to the nuclear plant, Beaver Valley's 2018 profits would be estimated at $173 million, as actual energy prices were significantly higher than forecasted. Beaver Valley profits are highly sensitive to energy prices. Every $1/MWh increase in annual average energy prices for Beaver Valley results in an increase in gross profits of $15 million.

Impact on Nuclear Generation Resulting from PJM Capacity and Energy Markets Reforms

Recent and pending reforms in PJM capacity, energy and reserve markets have, and will continue to have, a substantial impact on the profitability of nuclear power plants. As an example, it was noted earlier that some of these nuclear units did not clear in the PJM capacity market. This is a relatively recent market phenomenon, that coincides with both lower projected natural gas prices and changes in PJM's capacity market power mitigation rules. Lower natural gas prices can explain why single unit plants may have challenging economics under current PJM market constructs. Lower natural gas prices also lower LMP (energy prices) to such an extent that single unit reactors are economically challenged.

However, an additional contributor to nuclear units not clearing in the PJM capacity markets may be PJM's reforms to capacity market power mitigation mechanisms. When PJM implemented its Capacity Performance product that imposed higher penalties for non-performance during peak system usage conditions, such as during cold winter or hot summer days, it also weakened the capacity market power mitigation rules *to allow a unit to bid above its actual costs in the capacity market*. Therefore, a nuclear unit may not clear in the BRA, and not receive capacity payments, if a generator believed that overall revenues would still be higher for its fleet of generation by pushing capacity prices higher. Thus, if a unit does not clear in the capacity market this does not mean it is uneconomic.

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[10] S&P Global Market Intelligence, May 24, 2018.
[11] https://www.nrc.gov/docs/ML1811/ML18115A007.pdf.

Another pending capacity market reform is the Minimum Offer Price Rule (MOPR). Recently filed MOPR reforms could have the effect, on one hand, of increasing capacity prices to offset the potential price suppressive impacts of subsidized generation in PJM markets. This would have a positive impact on non-subsidized nuclear units. On the other hand, MOPR reforms may force a subsidized resource, such as some nuclear generation units in Illinois and New Jersey, to obtain capacity market payments outside of PJM markets, and could impose further penalty payments on subsidized units. This would negatively impact nuclear units that receive out-of-market revenues, such as Zero Emission Credits (ZECs).

Other energy and reserve market reforms pending before the Federal Energy Regulatory Commission (FERC), or to be filed in March 2019 should have a positive effect on nuclear generation by increasing energy prices. This will shift market revenues from capacity markets to energy markets – which will benefit nuclear units. As baseload generation units, nuclear plants derive most of their revenues from energy markets. Appendix A will provide further insight into each of these reforms.

In summary, PJM has, and continues to actively pursue, reforms in capacity and energy markets which should enhance earnings of nuclear power plants. However, some reforms, such as the MOPR reforms, may impose penalties on nuclear units that receive out-of-market subsidies, such as ZECs.

Nuclear Options for Pennsylvania

Option 1 - No State Intervention

At present, only one single-unit nuclear power plant, TMI, is clearly uneconomic in current and projected future PJM markets. Beaver Valley was profitable in 2018 and is projected to be profitable in the 2019-2021 period, based on average industry costs, and current market price projections. If FirstEnergy does not render capacity offer bids sufficient to clear in PJM capacity markets, its profits are significantly reduced – close to breakeven based on the IMM analysis. Absent further cost support for further out-of-market payments for Beaver Valley, it appears that the loss of zero-emissions generation may be limited to TMI under this scenario.

If there is no state intervention, Pennsylvania's competitive market policies, which have helped attract considerable investment in new natural gas generation, in particular, would remain undisturbed.

Annually, Pennsylvania's nine nuclear plant units produce roughly 82,000 GWh of carbon free electricity, which equates to about 34 million tons of avoided CO_2 annually at the 2017 PA average generator plant emissions rate of 816 lbs./MWh,[12] and approximately 39 million tons of avoided CO_2 at the PJM average generator plant emissions rate of 950 lbs./MWh.[13] Collectively, this represents 41% of the PA electric generator emissions of 81.9 million tons in 2017 at the Pennsylvania emissions rate. TMI alone accounts for 3.2 million tons of avoided CO_2 at the PJM average emissions rate, which is 3.4% of total 2017 generator emissions in Pennsylvania. TMI and Beaver Valley combined account for 10.3 million tons of CO_2 at the PJM average emissions rate, which is 11.1% of total 2017 generator emissions in Pennsylvania of 81.9 million tons.

It may not be proper to use average Pennsylvania or PJM emissions in estimating avoided emissions rates. A more accurate method of estimating average avoided emissions rate would be to model emissions through scenario analysis. This is beyond the scope of this paper. However, a rough estimate could be attained by substituting new combined cycle natural gas (CCNG) generation as a rough proxy for nuclear plant retirement scenarios, as this reflects all of the recent baseload generation construction in PJM. One study by the European Joint Research Center determined an emissions rate of post 2010 CCNG units of 344 g CO2/kWh,[14] which converts to an emissions rate of 758 lbs./MWh. This is not significantly different from the 2017 Average PA Emissions rate.

Pennsylvania's AEPS Act Tier 1 resources will provide an estimated 10,729 GWh of carbon free electricity per year by 2021, or roughly 13% of the carbon free electricity of nuclear plants. Thus, the loss of the entire fleet of nuclear plants in Pennsylvania would be a substantial step back in reducing

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[12] https://www.eia.gov/electricity/state/pennsylvania/.
[13] PJM, 2017 Pennsylvania State Infrastructure Report, May 2018.
[14] Green House Gas Emissions from Fossil Fuel Fierd Power Generation Systems, M. Steen, DG-JRC/IAM, European Joint Research Center,EUR 19754, p. 19/61, https://pdfs.semanticscholar.org/d666/1a01ee6a54f86fad283e4650e1074c795b7b.pdf.

carbon emissions in the Commonwealth. However, as noted above, only one plant is clearly uneconomic (TMI), and one plant is currently "on the bubble" (Beaver Valley). TMI provides an estimated 6,665 GWh per year of carbon free electricity, or about 2.7 million tons of avoided CO_2. Beaver Valley provides about 15,034 GWhs of carbon free electricity, or about 6.1 tons of avoided CO_2, using Pennsylvania's average generator plant emission rate. If AEPS Tier 1 growth requirements were extended at the current annual rate of increase in AEPS Act Tier 1 resources of 0.5%, it would take Pennsylvania 12.6 years to replace the lost carbon free electricity from TMI, and an additional 28.4 years to replace Beaver Valley.[15]

In conclusion, if the policy choice is to prevent backsliding on carbon emissions this is not a very viable option.

Another consideration with regard to nuclear plant retention is the cost of regional transmission investment required to sustain reliable network transmission service. PJM has evaluated these deactivation notices and found that TMI retirement will require no new incremental network transmission upgrades. However, Beaver Valley, should it retire, will require an estimated $182 million in incremental transmission investments if the two units retire in 2021.[16] The effect of this would be to accelerate these transmission projects relative to the retirement of Beaver Valley #1, coincident with its current license expiration in 2036. Accounting for the alternative of a later investment, escalation of transmission costs[17] and the net present cost of this later transmission investment,[18] the alternative current cost is approximately $114 million. Thus, the true net cost of transmission investment today, versus tomorrow, is an estimated one-time net present cost of $68 million.[19]

As more fully described in Appendix B, cost impacts related to regional power markets largely hinge on whether nuclear generation will be replaced by new combined cycle natural gas units. Historical trends support this as a very likely scenario. As such, cost impacts of the retirement of TMI and Beaver Valley are likely to be insubstantial.

Lastly, concerns have been raised about the potential for impacts to the reliability of regional power markets. A thorough study of the impacts of announced nuclear retirements in Pennsylvania concluded that the PJM system can withstand an extended period of stress while remaining reliable. Even in an extreme scenario, such as an extended period of severe weather combined with high

[15] The AEPS Act provides for an annual increase in clean Tier 1 resources of 0.5% of total Pennsylvania electricity consumption through 2021. Legislative amendments to the Act would be required to extend this annual increase post 2021.
[16] Assumes all costs are allocated to Pennsylvania customers. Some costs associated with PJM projects b3006, b3017.1, b3017.2 and b3017.3 will, however, be allocated to other states in PJM.
[17] See PPI industry data for Electric bulk power transmission and control, not seasonally adjusted, Series Id: PCU221121221121, Years: 2009 to 2019, data run February 26, 2019. Average escalation rate for transmission was 4.5% per year.
[18] Net Present Value calculations assume an internal cost of capital of 7.78%, based on a debt cost of 5.25%, ROE of 10.3% based on the MAIT Settlement, and a 50% equity ratio.
[19] $182-$114 million.

customer demand and a fuel supply disruption, the PJM system would remain reliable. Details of this study are described in Appendix C.

Option 2- Replace Nuclear Retirements with Renewables and Energy Efficiency

Clearly nuclear plants play a substantial role in carbon emission abatement. Replacement of this lost abatement could be achieved, but only after a number of years, as roughly quantified above. However, strategies, or a combination of strategies, could significantly reduce the time required to replace the emission free generation of nuclear plants at lower projected annual costs than retaining TMI. For example, expanded Act 129 energy efficiency; AEPS Tier 1 program extension; or Tier 1 expansion coupled with utility scale renewable energy procurement, through enablement of community solar programs.

Tier 1 incremental projects are largely dominated by regional wind development (45.9% of Tier 1 retired AECs in 2017). Other significant Tier 1 resources include wood/wood waste solids, Landfill gas, and Low Impact Hydro. The current market price is $6/MWh.[20] Tier 1 resources can be in-state or out-of-state. Based on the 2017 AEPS report, approximately 19% of certified Tier 1 wind resources were in-state. Using current owner/operator in-state solar AECs as a reference cost of replacing TMI generation, the cost would be $233 million per year at $35/MWh.[21] Using a lower cost resource, such as Tier 1 resources, including wind, would cost $40 million per year at $6/MWh. Using the work of the IMM, the cost of recovering going forward costs at TMI would lead to a subsidy estimated at $60 million per year, assuming the unit cleared in the capacity auction, and slightly over $90 million per year, assuming the plant receives no capacity revenues. Again, TMI has not cleared in the last four capacity auctions. In short, while Tier 1 renewable resources could replace TMI zero-emission generation at a lower cost, it would take a substantial amount of time at current Tier 1 growth targets, as noted prior, to effectuate this replacement, absent an expansion of AEPS requirements.

Using similar parameters for Beaver Valley, using the reference cost of small-scale current owner/operator in-state solar AECs of $35/MWh, the cost would be $526 million per year.[22] A lower cost resource, such as Tier 1 resources, including wind, would cost $90 million per year at $6/MWh. Per the IMM analysis, Beaver Valley is earning sufficient revenues to cover its costs going forward. However, actual plant operation and capital costs for FirstEnergy may be above industry average costs, or there may be additional one-time capital spending required that is not reflected in these nuclear industry statistics used by the IMM.

The analysis above is limited to the AEPS structure as it exists today. However, other potential legislative options could include Community Solar and procurement of new utility scale solar and wind

[20] Spectrometer US Environmental Report, February 22, 2019, for year 2019.
[21] Spectrometer US Environmental Report, February 22, 2019, for year 2019.
[22] Some large solar projects are in the development process that could lower these prices should they bid into AEC markets, including the 70MW Community Energy Solar facility under development to be operated by Adams Solar LLC in Adams County, Pennsylvania.

generation. Community Solar solutions help drive down the cost of distributed energy systems by expanding virtual net metering to non-owner/operator systems. This enables the build out of larger solar facilities and captures greater economies of scale. Lower costs of these systems are supported by underlying industry cost data.[23] Average installed solar capital costs for 2018 were $3.7/watt DC for residential systems, $3.1/watt DC for small commercial systems less than 500 kw, and 2.2 cents/watt DC for larger systems between 500 kw and 5,000 kw.

Long term utility scale solar and wind procurements might also offer opportunities. Recent procurements by the Illinois Power Authority (IPA) provide insight into the lower cost of utility scale solar and wind procurements. Prices for four recent utility scale long-term procurement for solar Renewable Energy Certificate (REC) auctions between September 2017 and December 2018 ranged from $4.26/MWh to $6.07/MWh. A long-term procurement auction held on August 31, 2017 for Wind RECs resulted in an average price of $4.26/MWh. During these 15 months, 4,000 GWhs per year of solar and wind electricity were procured by the IPA, or roughly 60% of TMI's emissions-free generation.

An additional source of carbon abatement is energy efficiency. Under Act 129, the Commonwealth will be reducing electricity use by 5,710 GWhs over a 5-year period, or just slightly below the emissions reduction impacts of TMI. These reductions were based on annual reductions in usage in the range of 0.5% per year to 1% per year, depending on the Electric Distribution Company (EDC). Each 1% usage reduction is the equivalent of 1,348 GWh per year. Thus, emissions reductions of TMI and Beaver Valley could, in theory, be replaced by incremental energy efficiency investments. For example, if energy efficiency goals were increased by 1% of statewide usage per year, the loss of the zero-carbon generation from these plants could be replaced in 5 and 11 years, respectively. Energy efficiency has no net cost to consumers. Net positive benefits have been observed for every year during implementation of the Act 129 Energy Efficiency and Conservation Act.[24]

In summary, Existing Tier 1 resources currently offer a lower cost solution to replacing emissions-free generation from TMI. Small scale distributed solar projects authorized under the AEPS Act are *currently* not a lower cost solution to TMI. However, at current rates of annual resource growth under the AEPS Act, it will take a number of years to replace both TMI and Beaver Valley emissions-free electricity. Energy efficiency also presents a "net benefits" solution to replacing emissions free generation, but also will take a number of years to replace both nuclear units. Other solutions, however – expansion of our existing AEPS and Act 129 energy efficiency programs, additional procurement of utility scale renewable resources such as wind and solar, and enablement of Community Solar programs - can be both cost effective and accelerate the replacement of emissions-free generation from nuclear plants.

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[23] LBNL, Tracking the Sun, Installed Price Trends for Distributed Photovoltaic Systems in the United States - 2018 Edition, September 2018.

[24] http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_129_information/act_129_statewide_evaluator_swe_.aspx; see annual reports and end of phase reports.

Option 3a – Expand the AEPS Act to Include a Nuclear Generation Tier

A new AEPS tier could be created to acknowledge the carbon free attribute of in-state nuclear generation – for example a "Tier Z", with an annual quantity equal to approximately 82,000 GWhs (the current approximate quantity of Pennsylvania annual nuclear generation).

Establishment of a Tier Z could certainly ensure that no nuclear plants in Pennsylvania retire. However, without constraints, the market for Tier Z Alternative Energy Credits (AECs) would be highly concentrated and, unavoidably, without attributes of a competitive market.

If the policy goal is to retain all Pennsylvania nuclear plants, based on the IMM analysis, the Tier Z AEC price would need to be about $9/MWh if the unit cleared in the capacity market, and $13.62 per MWh without the help of capacity market revenues. Total market costs would range from $700 million to over $1.1 billion per year.

If, however, a Tier Z approach were designed to retain all nuclear plants other than TMI, the estimated cost could be significantly reduced. Should the legislature desire to provide further funds to all remaining Pennsylvania nuclear plants, establishing a price based on the AEC costs of Tier 1 resources is one approach. Using a current AEC cost for Tier 1 resources of $6/MWh, this would provide additional funds of $453 Million to Pennsylvania nuclear plants other than TMI. However, as stated before, it has not been established that these plants require additional funding to recover going forward costs outside of PJM markets.

These out-of-market payments would also subject Pennsylvania customers to potential MOPR Minimum Offer Price Rule (MOPR) capacity market premiums and costs, depending on the outcome of the current PJM FERC filing. There is also residual legal risk in the execution of such an approach. Pennsylvania's competitive market policies, which have historically helped attract considerable infrastructure investment in generation, may result in less investment going forward due to market intervention by the state.

Options to mitigate the cost impacts to rate payers of a Tier Z approach, include:

1. Limit the quantity of Tier Z requirements to units that can substantiate economic need (New Jersey – Option 4), and
2. Impose a Market Price Index adjustment to Tier Z credit rates to ensure that rate payers do not over-subsidize plants when wholesale electricity market prices rise (Illinois), and
3. Credit any excess profits back to rate payers, during periods of very high market prices.

Option 3b – New Tier, Wherein Other Resources Qualify.

Another approach would be to create a new zero-emissions "Tier Y" category open to all zero-emissions resources, including existing Tier 1 resources under the current AEPS. This sets the value of carbon at the market cost of the marginal emissions-free resource based on the quantity of Tier Y resources established under the legislation.

Advantages of a such a program, in theory, is that competition by other resources would exert some level of discipline on Tier Y prices. The challenges of such a construct is that nuclear plants are very large sources of power. Market prices for Tier Y resources would be very volatile, as the supply/demand balance could shift substantially if even one nuclear power plant retires. It could take a number of years for market prices to stabilize – absent some type of additional market intervention (i.e. administrative price caps or Tier Y quantity adjustments). It is also not clear that a Tier Y approach would retain TMI. This approach would also provide additional funds to nuclear units which are already profitable. Lastly, other, more cost-effective resources, such as energy efficiency or low (but not zero) carbon resources would not be receiving an appropriate price signal.

Option 4 – Zero Emission Credit Program

A targeted nuclear support program could be legislated which strictly funneled financial support to those plants that can demonstrate a long-term financial need for out-of-market payments to compensate the nuclear unit for its environmental and health benefits, similar to the New Jersey legislative approach. Applicants for a subsidy would need to demonstrate and disclose financial need, operational fitness, meet certain performance metrics, and be responsible for PJM market non-performance penalties.

Under the New Jersey ZEC legislation, it is asserted that the zero emission certificate program set forth in its act is structured such that its costs are guaranteed to be significantly less than the social cost of carbon emissions avoided by the continued operation of selected nuclear power plants, ensuring that the program does not place an undue financial burden on retail distribution customers.[25] New Jersey may impose a retail cost of $0.004 per kilowatt-hour on the bill of retail customers which reflects the emissions avoidance benefits associated with the continued operation of selected nuclear power plants[26], which is roughly equivalent to $4 per MWh.

The advantages of this approach are that financial support could be individually targeted to minimize out-of-market payments required to support only at-risk nuclear plants. ZEC payments, based on the IMM analysis of TMI, are estimated to be $60-$90 million per year, depending on whether or not the unit cleared in the PJM capacity markets. Payments to Beaver Valley would be based on any additional financial information provided in support of the proposed need.

[25]P.L. 2018, CHAPTER 16, approved May 23, 2018, Senate, No. 2313, Section 1. b. (8) of the Act.
[26]Section 3. j. (1) of the Act.

This would reasonably ensure, if that were the desired policy goal, that no nuclear plants in Pennsylvania would retire and that the benefits of these zero-carbon resources would be uninterrupted. However, a ZEC program would shield the nuclear plants from competition, thus there may be reduced incentives for efficient, lowest cost operations. This could also disadvantage other carbon free resources, such as energy efficiency, large-scale solar and wind, or low carbon resources which may be more cost effective in the long run, relative to certain nuclear plants.

Again, with this option, a ZEC qualifies as an out-of-market payment which would subject Pennsylvania customers to potential MOPR capacity market premiums and costs, depending on the outcome of the current PJM FERC filing. There is also residual legal risk of execution of such an approach.[27] Pennsylvania's competitive market participants, which have helped attract considerable infrastructure investment in new generation historically, may invest less going forward due to market intervention by the state.

Option 5 – Establish a Carbon Market

There is currently no recognition of the cost of carbon emissions in the PJM markets, or, for that matter, in Pennsylvania. PJM markets do not recognize the cost of carbon emissions explicitly, other than through the RGGI states of Maryland and Delaware, and going forward, New Jersey and Virginia.[28] Energy efficiency investments in Pennsylvania under Act 129 do not incorporate the cost of carbon into the cost/benefit calculations. Illinois' Public Act 99-0906, otherwise known as the Future Energy Jobs Act, lists an explicit social cost of carbon emissions as an appropriate valuation of the environmental benefits provided by zero emission facilities (ZECs). The Social Cost of Carbon was determined by Illinois to be $16.50 per MWh, which is based on the U.S. Interagency Working Group on Social Cost of Carbon's price in the August 2016 Technical Update using a 3% discount rate, adjusted for inflation for each year of the program.[29]

A number of carbon market models exist, including a regional market-based greenhouse gas reduction program like RGGI, or engaging Congress to adopt a national carbon market, develop a state compact for a PJM wide carbon market, or supporting a Pennsylvania only carbon market, as in California.

Option 5a - Establish a Carbon Market for Pennsylvania

One variation of a carbon market approach is to establish a Pennsylvania carbon market, as California is implementing. Pennsylvania has existing authority to regulate carbon as a pollutant. Either this or a legislative approach could be used to establish a carbon price or market in Pennsylvania. Such a

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[27] Elec. Power Supply Ass'n v. Star, 2018 WL 4356683 (7th Cir. 2018); Coalition for Competitive Elec, et al. v. Zibelman, 2018 WL 4622696 (2nd Cir. 2018).

[28] The clean energy attribute value of RGGI state resources will be reflected in the bid offers of generators into energy markets in those RGGI states.

[29] Illinois' Public Act 99-0906, Section 1-75, Subsection (d-5) (B) (i).

market would have most of the same advantages and disadvantages of RGGI. It would provide more state control of all design elements of the carbon market.

The challenges of this approach are the potential for competitive industry inequities across more state borders and greater carbon price volatility. Any such proposals would need to address these additional issues. PJM has not yet developed a method of state border price adjustments to ensure fair competition between in-state and out-of-state carbon emission generators. This issue will be taken up again in 2019, per PJM management. A PJM border adjustment mechanism, however, would not address competitive commercial and industrial customer inequities.

California's carbon allowance market price is currently valued at $17.15 per metric ton of CO_2.[30] This translates into an electricity market price of $6.3 to $7.4 per MWh based on the 2017 average generator emissions rate in Pennsylvania and PJM, respectively.

Option 5b – Link with the Regional Greenhouse Gas Initiative (RGGI)

Linking with RGGI would provide several benefits including providing an additional boost to Pennsylvania's four dual-unit nuclear power plants – likely sufficient enough to keep these units profitable. However, it would be insufficient to keep TMI from being retired at current carbon market prices. Current RGGI market prices for carbon are approximately $5.30/short ton, which, when applying the 2017 system average PJM emissions rate of 950 lbs./MWh, is equivalent to $2.50/MWh. As an example, each $1/MWh increase in LMP adds about $15 million to the bottom line of Beaver Valley. With that said, the impact on LMPs from the inclusion of a carbon price into energy market offers (specifically, the particular carbon price adder to the energy bid by the marginal plant) requires detailed modeling to reasonably project localized pricing impacts to Pennsylvania electricity consumers.

RGGI provides member states with flexibility in how carbon revenues are remunerated, including returning revenues to customers, reinvestment in energy efficiency or renewable energy programs, or low-income assistance programs.

Participation in RGGI would place Pennsylvania's residential, commercial, and industrial customers on par with other member states; create a larger more stable regional market for carbon; internalize the cost of carbon across both producers and consumers of electricity; incent more efficient investment of capital than other support mechanisms; while maintaining Pennsylvania's commitment to competitive markets by providing a price signal.

The net cost to consumers is likely to be minimized under such a carbon price mechanism, while carbon credit revenues may be returned to customers and businesses to further mitigate cost or competitive industry impacts.

[30] A metric ton is 2,204.62 lbs.

A “Border Adjustment” wholesale market pricing mechanism has not been developed by PJM to ensure fair competition from non-RGGI states within the PJM RTO, as noted above. Absent such a “Border Adjustment” mechanism, further modeling would be required to measure the negative impact to Pennsylvania natural gas generation, and most notably, coal related businesses. A PJM state compact, wherein other states, such as Ohio, Indiana and Illinois agreed to link to RGGI could also address this inequity in wholesale electricity competition, as well as impacts to competitive commercial and industrial businesses.

Option 5c – Establish a PJM-wide Carbon Market

An extensive state compact that established a carbon price for all PJM states would provide a more cost-efficient solution to carbon emissions abatement. Such a mechanism could address a meaningful level of competitive inequities across electricity markets, and commercial and industrial businesses relative to other options, such as a state-level carbon price, or RGGI membership. Carbon markets allocate resources efficiently across all market sectors, including all generation, load reduction (energy efficiency, and demand response), and carbon capture investments.

Option 5d – Participate in a National Carbon Market

Of course, a national carbon market would be the most efficient solution for achieving carbon emission goals. It would also resolve most competitive industry inequities, other than imported goods, which would otherwise need to be addressed by tariffs or similar adjustment mechanisms. However, while most competitive market inequities are resolved by a national carbon market, such legislation is unlikely to render TMI economic.

APPENDICES

Appendix A

PJM Capacity and Energy Market Reforms

Capacity Performance Market Reforms: When implementing its Capacity Performance reforms, PJM permitted units to bid into capacity markets at the higher of actual going forward net costs, or the Net Cost of New Entry (NetCONE) of the reference Combustion Turbine (CT) unit.[31] This NetCONE value is substantially above historical capacity prices in PJM. Since capacity markets have been found to be uncompetitive, this reform essentially enabled units to exert market power in capacity markets by bidding some units as high as NetCONE, thus altering the supply/demand balance in the Regional Transmission Organization (RTO) region, or subzone, and raising prices for capacity through economic withholding strategies. In this context, a nuclear plant owner could bid into the capacity markets with its nuclear unit(s) at above cost, thus not clearing the nuclear unit(s) in the forward capacity auction, but otherwise raising the capacity cost for the remainder of its generation fleet. Though capacity market payments can be an important part of baseload generation, a unit not clearing in the capacity market does not by itself mean a unit is uneconomic.

Minimum Offer Price Rule (MOPR): PJM has recently filed a revision of its Minimum Offer Price Rule (MOPR) proposal.[32] On the one hand, PJM filed a plan to isolate subsidized resources, like some nuclear plants in Illinois and New Jersey, from the capacity market, by creating a Resource Carve-Out (RCO) mechanism. This mechanism essentially ensures that subsidized resources clear in the capacity market by being bid in at a capacity price of zero in Step 1, of the auction, therefore allowing non-subsidized units to set the capacity clearing price. However, in tandem with this RCO filing, PJM also filed an Extended Resource Carve-Out (Extended RCO) mechanism, which included a second step in the capacity auction process that removes the RCO units from the bid stack and reprices the capacity market without removing any demand from the market. Thus, higher cost non-RCO units, that didn't clear in the original auction, would set the capacity market clearing price. In addition, the RCO units would need to pay these non-clearing generation units on the margin in Step 2 the difference between the final clearing price in Step 2, and the bid offers from the higher cost non-RCO units, thus imposing an additional cost barrier to nuclear units seeking RCO status. In summary, the Extended RCO proposal would result in higher capacity prices paid to all generation resources that cleared in Step 1 of the auction and impose a penalty on RCO units paid to marginal units didn't clear in Step 1 but set the price in Step 2 of the auction. Ultimately, it will be electricity customers that will pay the costs resulting from PJM proposals. A FERC decision on the PJM filing is anticipated sometime in March 2019.

Operating Reserve Demand Curve Reform: PJM has recently announced its intent to file with the Federal Energy Regulatory Commission (FERC) its Operating Reserve Demand Curve reforms in March

[31] PJM asserted that higher non-performance penalties would raise opportunity costs of committed units to the level of NetCONE. However, the persistent level of excess capacity has resulted in no Capacity Performance penalties since implementation. Thus, the theoretical foundation for reforming the market power mitigation rules has not transpired in actual practice. PJM has no plans to reexamine these assumptions

[32] FERC Docket No. EL18-178-000.

2019, which, when co-optimized with LMP, were last projected to increase energy prices by 7.3%.[33] For TMI and Beaver Valley, this 7.3% increase, this translates into an estimated $15 million and $34 million per year in additional energy revenues, respectively. The actual impact related to these reforms may vary, depending on FERC's actions on these future filings, regional price variations, and changes in market behavior of existing or new market participants.

Recategorization Inspection and Maintenance Costs: PJM has already filed to eliminate a current restriction that prevents sellers of energy from Combined Cycle Natural Gas and Combustion Turbine plants from including inspection and overhaul (I&O) costs in their energy market offers, as opposed to including these costs in capacity market offers today. Such a change is likely to increase energy market costs, and, over time, decrease capacity market costs. PJM has not quantified the impact of this change. I&O costs embody a substantial percentage over overall inspection and maintenance costs of these units. This could be a meaningful increase in energy prices.

Fast Start Resources Proceeding: Lastly, FERC issued an order requiring RTOs, like PJM, to file modifications to allow generation units that have a minimum run time of one hour or less to include commitment costs of these fast-start resources (start-up and no-load costs) to be reflected in (energy) prices.[34] PJM is arguing for a different measure of what constitutes fast-start resources (defining those as having a start-up time of two hours or less and a minimum run time of two hours or less, instead of 1 hour). PJM has not quantified the impact of this change on energy market revenues, but the impact should increase energy market revenues, and, over time, decrease otherwise applicable capacity prices, which will benefit nuclear profitability.

[33] https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-05-simulation-results-summary-price-formation-proposal.ashx. Slides 6 and 10.
[34] Docket No. EL18-34-000, Issued December 21, 2017.

Appendix B

Cost Impact of Nuclear Plant Retirements on Regional Power Markets

A number of dueling cost impact studies on the loss of nuclear power in Pennsylvania have been undertaken. A 2016 study by The Brattle Group[35] concluded that Pennsylvania consumers would pay $788 million more annually (2016$) and $6.6 billion more over the next ten years (on a present value basis) without these plants. This study appears to assume that all nuclear plants in Pennsylvania close, and assumes that only a small amount of this generation is replaced by new natural gas plants in Pennsylvania, thus, transforming our state from a strong exporter of power (24%), to a moderate importer of power (12%). Such assumptions are not well supported. Pennsylvania is the second largest producer of natural gas in the nation, and, as such, has a strong foundation for being a dominant source for replacement power for any shuttered nuclear plants.

A recent analysis by Seth Blumsack,[36] found that capacity and energy prices would increase only in the case where Beaver Valley and Three Mile Island were to shut down *without replacement*. The net impact on electricity costs in Pennsylvania thus depends on the pace at which gas-fired capacity enters the market as nuclear capacity is exiting the market. While future market outcomes are uncertain, this paper illustrates the impacts of different gas generation build scenarios on ameliorating the impacts of nuclear retirements. The analysis concludes that the impact on Pennsylvania ratepayers over a three-year period, assuming that both Beaver Valley and Three Mile Island retire at the same time, would range from an electricity cost increase of $400 million in the scenario where nuclear deactivations are not replaced by any new capacity, to an electricity cost decline of nearly $500 million in the scenario where a large gas generation build-out more than compensates for lost nuclear capacity.[37]

At a very high level, nuclear units are not on the margin in PJM energy markets. They currently contribute nothing to LMP at the margin of PJM energy markets. Rather, coal and natural gas prices are the underlying drivers for PJM energy markets.[38] As noted by Blumsack, the rate of generation unit replacement of nuclear units is the key factor in future energy markets.

Underlying announcements of new generation plants in PA support scenarios wherein any nuclear power plants decommissioned would very likely be replaced mostly by new, efficient combined cycle natural gas power plants, many of which would be developed in-state, and, to a lesser degree, renewable resources related to state Renewable Portfolio Standards (RPSs). In short, it is not clear that the retirement of these two nuclear power plants in Pennsylvania will have a significant impact on PJM power prices under today's resource environment.

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[35] The Brattle Group, Pennsylvania Nuclear Power Plants' Contribution to the State Economy, December 2016.
[36] The Electricity Journal 31 (2018) 57-64, Impacts of the retirement of the Beaver Valley and Three Mile Island nuclear power plants on capacity and energy prices in Pennsylvania, Seth Blumsack, Energy Policy and Economics, John and Willie Leone Family Department of Energy and Mineral Engineering, Pennsylvania State University, State College, PA, United States.
[37] Blumsack at 64.
[38] http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q3-som-pjm-sec3.pdf, p. 188, tables 3-84 and 3-85.

Appendix C

Impact of Nuclear Retirements on the Reliability of Power Markets

Overall, Pennsylvania is a strong net exporter of electricity generation, with 41.5 GW of generation, and a peak day usage of 29.6 GW, the largest in the United States. As of December 31, 2017, 9.6 GW of additional generation capacity was under construction in Pennsylvania.[39] Summer peak load growth for the PJM RTO is projected to increase very modestly, with an average 0.3% per year increase over the next 10 years, and 0.4% increase over the next 15 years.[40] Given these supply and demand fundamentals, Pennsylvania is anticipated to continue to have adequate generation, and continue in its role as an exporter of power to the PJM RTO. However, reliability is ensured by PJM on a regional level. On this level, the transmission system and the level of generation are currently in a very reliable state relative to historical infrastructure build.

PJM recently performed an analysis to test the resiliency of its system to severe system stresses and concluded that the PJM system is reliable today and will remain reliable into the future. In the analysis, PJM stress-tested the fuel delivery systems serving generation in the PJM region under more than 300 extreme scenarios to identify when the system begins to be impacted and to identify key drivers of reliability risk. These scenarios included:

1. Generation retirements – base case assumption of 4.8GW of nuclear and 7.5GW of coal units, with 2 other scenarios of 15.6GW and 32.1GW of coal and nuclear plant retirements.
2. High customer demand - a 14-day period of cold weather with typical winter load and generation retirements announced as of Oct. 1, 2018.
3. Fuel delivery failures, and
4. Fuel disruptions

Key elements, such as on-site fuel inventory, oil deliverability, location of a fuel supply disruption, availability of non-firm natural gas service,[41] pipeline configuration and demand response become increasingly important as the system comes under more stress.

The study removed the capacity of all announced generation retirements as of October 1, 2018, including nuclear retirements such as TMI and Beaver Valley, with a resultant generation installed capacity reserve of 25.8%, which remains far above the required generation reserve requirement of the last generation capacity auction of 15.8%.[42] PJM concluded that its system can withstand an extended period of stress while remaining reliable. Even in an extreme scenario, such as an extended period of

[39] 2017 Pennsylvania State Infrastructure Report, May 2018.
[40] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-forecast-report.ashx?la=en, p 2. PJM is a summer peaking RTO. As such, summer demand increases drive reliability requirements for the RTO.
[41] Non-firm gas supply means the power plant has non-firm transportation contracts (also called interruptible) for the delivery of natural gas supply, which are lower priority, depend on the availability of pipeline capacity, and may be interrupted should conditions warrant.
[42] Fuel Security Analysis: A PJM Resilience Initiative, table 1, p. 12. The base case used in this study reduced the installed capacity of nuclear units to 28.8GW in PJM, which reflects the announced retirements of 4.8GW of nuclear generation and 7.5GW of coal-fired generation, table 4, p. 17. https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx?la=en.

severe weather combined with high customer demand and a fuel supply disruption, the PJM system would remain reliable.

It was only under very extreme modeling scenarios - under escalated retirement scenarios looking out 5 years when combined with extreme winter load, the system may be at risk for emergency procedures and load loss. These escalated retirement scenarios essentially assumed the level of reserves were brought down to the minimum reliability requirement of 15.8%.[43]

Absent substantial reforms in the Variable Resource Reliability demand curve used to procure capacity resources, this low level of reserves is highly unlikely, and, in fact, has never occurred in the entire history of PJM capacity procurement.

[43]https://www.pjm.com/-/media/committees-groups/committees/mrc/20181101-fuel-security/20181101-fuel-security-phase-1-analysis-results.ashx?la=en, Escalated Scenario 1 assumed an additional 13.6GW of nuclear and 18.5GW of additional coal plants retired [residual nuclear flee if 15.2GW]. Escalated Scenario 2 assumed an additional 9.4GW of nuclear and 6.2GW of additional coal plants retired [residual nuclear capacity of 19.7GW]. Under both scenarios, generation replacement was limited to only meeting the minimum allowed reserve requirement of 15.8%.

Appendix D
RGGI Summary

The Regional Greenhouse Gas Initiative (RGGI) is the country's first market-based program to reduce emissions of carbon dioxide ("CO_2") from existing and new power plants and has now been operating since 2009 - for over nine years. The scope of RGGI is significant: the current set of RGGI states account for more than one-eighth of the population in the U.S. and more than one-seventh of the nation's gross domestic product.[44] The ten original RGGI states were Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. New Jersey participated in the first three years of the RGGI program and withdrew its participation at the end of 2011. New Jersey recently issuing an executive order to reinstate its prior participation in RGGI, Virginia moving forward with legislative priorities to participate with RGGI states. Some important design elements are as follows:

1. Who must buy CO_2 Allowances? RGGI requires owners of emitting power plants to purchase CO_2 allowances. Power Plant owners recover these costs in their energy offer bids in the wholesale markets. Shortly after the end of each three-year compliance, every affected source must retire a number of allowances equal to the total tons of CO_2 emissions from the source over the three-year compliance period (one allowance equals one ton of emissions). Affected units may obtain allowances at various points in time prior to the end of the compliance period. Sources can purchase, bank, and use allowances bought at any auction for a given compliance period within the three-year compliance period. Allowances can be purchased and banked for use beyond the compliance period in which they were purchased. Sources can meet up to 3.3 percent of their CO_2 compliance obligation through the purchase of offsets – that is, GHG-reduction projects outside the power sector.
2. How are targets set? The original cap was set at 188 million tons annually. This cap is reduced each year. By 2017, 84.3 million allowances were available, a 55% reduction. The regional cap is apportioned to states in a manner based generally on emissions from the affected sources (i.e., fossil fuel power plants that are 25 megawatts or more in size), according to an agreed-upon ratio that roughly reflects each state's relative share of regional CO_2 emissions from the power sector as of a historical time period. The RGGI cap is set in a public process that includes input with and by the state departments of environmental protection and state public utility commissions from the RGGI states.
3. Use of carbon fee proceeds: RGGI states have received virtually all of the nearly $2.8 billion in proceeds from CO_2-allowance auctions and disbursed them back into the economy in various ways, including through expenditures on: energy efficiency ("EE") measures and programs; renewable energy ("RE") projects; GHG-emission reduction measures; direct electricity consumer bill

[44] The Analysis Group, "THE ECONOMIC IMPACTS OF THE REGIONAL GREENHOUSE GAS INITIATIVE ON NINE NORTHEAST AND MID-ATLANTIC STATES", Review of RGGI's Third Three-Year Compliance Period (2015-2017), April 17, 2018, p. 1.

assistance, including for low-income households; and education and job training programs.[45] Participating states retain jurisdiction over how funds are dispersed.[46] Pursuant to an MOU, 25 percent of the state's allowances should be allocated "for a consumer benefit or strategic energy purpose".[47] The use of the RGGI funds are set by each state either in their enabling RGGI statutes or regulations.

4. Determination of carbon reductions. RGGI states collectively decide aggregate annual carbon cap reductions. Current annual carbon emission reductions are set at 2.5% through 2020, consistent with the RGGI model rules that each state must adopt.

5. Centralized carbon allowance trading. States can elect to sell their carbon allowances in centralized auctions conducted quarterly by RGGI, Inc. on behalf of the RGGI states, or allocate allowances in a manner consistent with their own policy objectives. The vast majority of states elected to participate in this centralized auction. Funds collected in auctions are transferred to each state for inclusion in the state's budget process consistent with that state's enabling statute and/or regulations.

6. High price mitigation mechanisms: RGGI has a Cost Containment Reserve ("CCR") trigger price, which, when hit, causes additional allowances to be sold into the market to lower carbon prices. The trigger price was $10 in 2017, rising 2.5 percent each year thereafter through 2020 (to account for inflation). After 2020, the trigger price will rise by 7 percent in each subsequent year. Subsequently, the trigger price was increased to $13 in 2021, increasing 7% annually thereafter.

7. Market Power Monitoring: An independent market monitor assesses the performance of the auctions to ensure that they are administered according to auction rules, and that there is no anti-competitive behavior in the market. There is also a 25 percent cap placed on purchases by a single buyer or group of affiliated buyers in each auction.

8. Low price mitigation mechanism: A price floor is established in 2014 at $2.00 and increases annually by 2.5 percent. RGGI subsequently created a CO_2 emissions containment reserve allowance (CO_2 ECR allowance) that is withheld from sale at an auction for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs. The ECR trigger price in calendar year 2021 will be $6.00 and increases 7 percent annually thereafter.

Economic studies conducted on RGGI demonstrate net positive benefits from membership. Over the last three years (2015-2017), the RGGI program led to $1.4 billion (net present value ("NPV"))

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[45] Id. P. 2.

[46] Id. P. 5. Overall, the distribution of spending across the RGGI states was as follows: 52% on EE; 18% on RE projects; 13% on bill-payment assistance to consumers; 7% on program administration; 4% on GHG-emission reduction programs; 3% on clean technology research and development; 2% on education, outreach, and job training; and 1% for payments into a general fund. Individual state expenditures varied significantly across these categories.

[47] Id.p. 16. MOU Section 2.G.

of net positive economic activity in the nine-state region.[48] Since RGGI's commencement in 2009, energy and dollar savings resulting from all states' investments in EE and RE has more than offset the wholesale market price increases associated with inclusion of allowance costs in market bids.[49]

Taking into account the gains and losses to consumers and producers, RGGI Compliance Period 3 [2015-2017] led to overall job increases amounting to thousands of new jobs over time. According to the Analysis Group, the net effect is that RGGI activity during the 2015-2017 period leads to over 14,500 new job-years, cumulative over the study period, with each of the nine states experiencing net job-year additions.[50]

[48] Id. P. 4.
[49] Id. P. 5.
[50] Id. at 9.

Appendix E

Summary of Illinois Nuclear Legislation

Legislation was referred to as the Public Act 99-0906 ("Act"), House Resolution 1146, also known as the Future Energy Jobs Act, which was signed into law in December 2016 and became effective June 1, 2017. The Illinois Commerce Commission's (ICC) approved the Zero Emission Credit (ZEC) procurement plan of the Illinois Power Authority (IPA) in Docket No. 17-0333. The IPA's evaluation criteria are fully described in the IPA's Final Approved Zero Emission Standard Procurement Plan subject to the modifications on September 11, 2017, and the final approval of the procurement of ZECs was granted on October 31, 2017, less than 1 year after signing of the Act.

A ZEC is a tradable credit representing the environmental attributes of one megawatt hour of energy produced by a zero-emission facility. A zero-emission facility is defined as a nuclear facility, located in PJM or MISO, that further provides carbon free energy, and minimizing sulfur dioxide, nitrogen oxide, and particulate matter emissions that adversely affect the citizens of the State of Illinois. The procurement process is designed to favor Illinois resources based on the localized emission reduction benefits. Unit winners of ZECs were Quad Cities, Units 1 and 2, and Clinton Unit 1, both located in Illinois.

The overall annual target quantity of ZECs of 20,118,672 ZECs was determined in the ZES Plan on the basis of the amount equal to approximately 16% of the actual amount of electricity delivered by Ameren and ComEd during the calendar year 2014 and an amount equal to approximately 16% of the portion of power and energy procured by the IPA for MidAmerican Energy Company (MEC) for the delivery year commencing June 1, 2016. Coincidentally, this was also equal to average of the state's Renewable Portfolio Standard (RPS) targets for the 2017-2023 period.

For the first delivery year June 1, 2017 through May 31, 2018, the ZEC price paid to each facility will equal $16.50/MWh, the Social Cost of Carbon, as specified in Public Act 99-0906. As a result of cost caps included in Public Act 99-0906, some contractual volumes may not be paid for during the delivery year and may be paid for in a subsequent delivery year in which unpaid contractual volumes can be paid without exceeding the cost caps. Beginning with the delivery year commencing June 1, 2023, the [Social Cost of Carbon] price per MWh shall increase by $1/MWh and continue to increase by an additional $1/MWh each delivery year thereafter. However, the Social Cost of Carbon is then required to be adjusted based on a Market Price Index (MPI), which is initially set at $31.40, and which represents a proxy rate for compensation in energy and capacity markets in PJM and MISO. To the extent the MPI increases above $31.40, the ZEC credit price would decrease. In short, the Illinois legislation has a mechanism to adjust the price paid for carbon-free attributes of nuclear plants in the event wholesale market prices increase. The ZEC mechanism terminates on January 1, 2028.

All customers pay the ZEC costs, based on a cents/kWh fee. However, important consumer protection provisions cap the amount payable at 1.65% of the per kilowatt hour rate paid by eligible retail customers during the year ending May 31, 2009 multiplied against retail customer load. For 2017-2018, the total maximum amount that can be spent to procure ZECs for all the utilities under this applicable cap was $234,827,816, which is lower than the $331,958,084 amount based on the ZEC Contractual Volume and the applicable ZEC Price for delivery year 2017-2018. The estimated 5,886,683 unpaid ZECs will therefore be eligible for payment in a future delivery year when the rate cap does not limit the total amount paid for ZECs in that year.

Permissible ZEC Contract Termination Provisions include:

- Standard force majeure conditions that are outside of the control of the zero-emission facility as described in Section 1-75(d-5)(1)(D)(ii).
- The zero emission facility can terminate its ZEC contract in the event legislation is enacted by the General Assembly that "…imposes or authorizes a new tax, special assessment, or fee on the generation of electricity, the ownership or leasehold of a generating unit, or the privilege or occupation of such generation, ownership, or leasehold of generation units by a zero emission facility."
- The zero-emission facility can terminate its contract if the facility requires capital expenditures of more than $40 million that were unknown or unforeseeable at the time it executed the ZEC contract and which a prudent owner or operator would not undertake.
- The zero-emission facility can terminate its ZEC contract if the Nuclear Regulatory Commission terminates the facility's operating license.

Appendix F

Summary of New Jersey Nuclear Legislation

Overall Description:

- Bill creates a ZEC: "Zero emission certificate" or "ZEC" means a certificate, issued by the board or its designee, representing the fuel diversity, air quality, and other environmental attributes of one megawatt-hour of electricity generated by an eligible nuclear power plant selected by the board to participate in the program.
- Eligibility Criteria: An “eligible” nuke plant must provide to the NJ BPU certified cost projections over the next 3 energy years that include O&M expenses, fuel expenses, non-fuel capital expenses, the cost of operational and market risks that would be avoided by ceasing operations and any other info to demonstrate that the nuke plant’s fuel diversity and air quality attributes are at risk of loss because the nuke plant is cash negative on an annual basis or, alternatively, is not covering its costs, including cost of capital, on an annual basis.
- Who pays the Nuclear Plant: Each utility will have to buy ZECs on a monthly basis from each selected nuke plant with payment due within 90 days of the end of the energy year. Each utility gets full cost recovery for the ZECs and the costs of the NJ BPU’s implementation of the program through a non-bypassable surcharge to all customers.

ZEC Price:

- Price is fixed at $0.004/kWh for the first 2 years. However, If the Board determines, in its discretion, that no nuclear power plant that applied satisfies the objectives of the Act, the Board shall be under no obligation to certify any nuclear power plant as an eligible nuclear power plant.
- BPU has the right to modify the $0.004/kWh charge as early as during the full third year of the first ZEC payment term if the BPU decides not to continue the program, provided the BPU determines that the reduced rate “will nonetheless be sufficient to achieve the State’s air quality and other environmental objectives by preventing the retirement of the nuclear power plants that meet the eligibility criteria established pursuant to subsections d. and e. of this section
- BPU also has the authority to modify the $0.004/kWh charge at the beginning of the second three-year ZEC payment term and in subsequent periods under certain defined conditions.

ZEC Quantity:

- Per the Act, the highest ranked units, in order, will be selected to receive ZECs until their combined total capacity equals no more than 40% of the total number of MWh distributed in the State in the 2017 energy year.

- Units that are awarded ZECs will receive them for the period between April 19, 2019 through May 31, 2019 and the following three energy years (2019–2020, 2020–2021, 2021–2022) per the Act.

Labor:

- A selected nuclear power plant shall not lay off any personnel unless the lay-off is due to employee misconduct or underperformance issues, or due to the suspension or cessation of the selected nuclear power plant's operations as provided in subsection k. of this section.

Excuse from performance of selected units receiving ZEC revenues:

- Force majeure – due to an event beyond its control, including but not limited to acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, labor dispute, labor or material shortage, sabotage, or explosion.
- State Law Regulatory Out – significant new tax, special assessment, or fee on the generation of electricity, the ownership or leasehold of a generating unit, or the privilege or occupation of the generation, ownership, or leasehold of generation units by a selected nuclear power plant;
- Regulatory Out – impacting ZEC value - State or federal law is enacted that materially reduces the value of a ZEC, or the board exercises its discretion to reduce the amount of the per kilowatt-hour charge pursuant to paragraph (3) of subsection j. of this section;
- Unanticipated large CapEx – nuclear power plant requires capital expenditures in excess of $40,000,000 that were neither known nor reasonably foreseeable at the time it was selected to receive ZECs, and the capital expenditures are expenditures that a prudent owner or operator of a selected nuclear power plant would not undertake.
- Loss of Nuclear Regulatory Commission license.
- Non-performance penalty – If a selected nuclear power plant ceases operations during an eligibility period for any reason other than those specified in the bill, the plant is to pay a charge to the utilities that purchased ZECs from the selected nuclear power plant in an amount equal to the compensation received for the sale of ZECs since the board's last determination of the selected nuclear power plant's eligibility to receive ZECs.

ZEC Program evaluation – after 10 years

ZEC Application Requirements:

- Must be licensed to operate by the United States Nuclear Regulatory Commission beyond 2030.
- Must make a significant and material contribution to air quality in New Jersey.
- Must provide fuel diversity, air quality, and other environmental attributes that are at risk of loss without a material financial change.

- Must receive no payments or credits for fuel diversity, resilience, air quality, or other environmental attributes that would eliminate the need for ZECs.
- Must include the requisite application fee of $250,000.

ZEC Status:

- All 3 nuclear units in New Jersey have applied for ZECs
    - Salem 1 Generating Station [57.41% PSEG, 42.59% Exelon] – Nameplate 1,170MW
    - Salem 2 Generating Station [57.41% PSEG, 42.59% Exelon] Nameplate capacity 1,170MW
    - Hope Creek Generating Station [100% PSEG] – Nameplate - 1,291MW
- Commission Decision on awards is pending before the NJBPU. A Decision is required by April 18, 2019.