JOINT HEARING OF THE SENATE CONSUMER PROTECTION AND PROFESSIONAL LICENSURE COMMITTEE AND THE SENATE ENVIRONMENTAL RESOURCES AND ENERGY COMMITTEE

Testimony Of

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Regarding
Alternative Energy Portfolio Standards (AEPS) Act

Harrisburg, Pennsylvania
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Chair Tomlinson, Chair Boscola, Chair Yaw, Chair Yudichak and Members of the Committees

Thank you for inviting me here today to testify on the important issues surrounding the Alternative Energy Portfolio Standards Act (AEPS) in Pennsylvania and the best path forward to achieve our energy and environmental goals. I think it is particularly timely to be having this joint Committee hearing. There have been numerous changes in our energy markets and our environmental and regulatory backdrop since the AEPS was enacted. I also think it is particularly critical to include consumers in these discussions as any decisions or legislation will have a profound impact on consumers' energy bills as well as the type of energy service consumers receive.

In representing Pennsylvania's utility consumers, my primary responsibility is to ensure that Pennsylvania consumers enjoy safe and reliable service at reasonable prices. For electric service, it is critical in my view, that consumers have an electric system that is reliable, efficient, economic, environmentally sustainable, and diverse. We have worked over the decades, both at the state and federal level, to achieve these goals in the most cost-effective manner for consumers.

When the Alternative Energy Portfolio Standards Act was first considered in 2004, my Office saw the potential benefits to consumers of further developing renewable and advanced resources, particularly as there was a concern that the generation rate caps that were a foundation of our restructuring process might expire at a time of high natural gas prices. The types of generation that could be developed through the Alternative Energy Portfolio Standards Act would serve to mitigate the impact of volatile price increases of fossil fuels that were predominant then, and remain predominant, in setting the market clearing prices in the PJM wholesale energy markets. These new resources also could contribute to the diversity of our generation resources, and as many types of renewable generation are relatively small, they could be spread throughout the grid, thus improving the reliability of the grid.

In 2004, many renewable and alternative resources were still in the development stage, and we saw a benefit to supporting those resources in a manner that would allow them to compete in the future with existing types of generation. This was particularly true in light of the high price of natural gas at the time and the growing recognition that carbon emissions from fossil fueled power plants might need to be regulated in the future. The AEPS took the route of providing a form of subsidy to specific types of resources, divided into Tier I and Tier II, with gradually increasing percentages of the resources needed each year through 2021. The AEPS established an alternative energy credit (AEC) as the mechanism to achieve and monitor these goals. One of the critical features, and consumer protections, is that the AECs are competitively procured (in accordance with 66 Pa.C.S. §§ 2807(e)(3.5) and (3.7)) to ensure the AECs are acquired at the least cost over time. It was also the expectation that the AEC price would adjust downward over time as the cost of the renewable and alternative resource development went down, as supply increased, and/or as wholesale market prices increased. Each of these factors would result in a lower AEC price being sufficient to make the renewable and alternative generation resources competitive.

The AECs paid under the AEPS were, for the most part, intended to spur development of resources and technologies and represented a limited amount of a customer's usage. Since we were operating in a retail choice market, if customers wanted to further support renewable resources in greater quantities, customers could choose products from alternative electric generation suppliers with greater percentages of these resources. These were some of the most popular products selected by customers under retail choice.

In its *2017 Report on the Alternative Energy Portfolio Standards Act of 2004*, the Public Utility Commission and Department of Environmental Protection found that the cost of compliance with AEPS in 2017 was $122,717,631, or about $0.001 cent/kwh. See, *2017 Annual Report: Alternative Energy Portfolio Standards Act of 2004*, Appendix A, Table 2. The PUC/DEP Report also estimated that the cost of compliance to consumers at the 18% requirement in 2021 will be $103 million on an annual basis. See, *2017 Annual Report: Alternative Energy Portfolio Standards Act of 2004*, Appendix A, Table 5.

With technological advances that are continually reducing the cost of these alternative energy resources to levels that are increasingly competitive in the wholesale markets, with the potential for higher wholesale market prices in PJM as PJM implements new requirements to more accurately value resources and resource attributes, and with greater participation by many states in the Regional Greenhouse Gas Initiative (RGGI) that places a price on carbon emissions that is included in the PJM energy price, the role and ability of these resources to compete in the marketplace is greatly improved. In fact, the declining cost of AEPS compliance projected for 2021 and the observed forward prices appear to reflect these fundamentals.

The subsidies provided by the AEPS were limited in scope covering a maximum of 18% of usage and gradually increasing over a 17 year period. Direct subsidies such as received from renewable portfolio standards, if not carefully tailored, can distort our wholesale markets, increase consumers' bills without commensurate benefit, and as the PJM Market Monitor has often said, become "contagious." Direct, long term subsidies place the proverbial thumb on the scale for certain resources at an additional cost to ratepayers. By putting the proverbial thumb on the scale for certain resources, dollars can be diverted from other efficient and innovative solutions that the market may incentivize. The additional costs and benefits of a direct subsidy approach must be carefully weighed, particularly in light of the market mechanisms that now exist and can be used to achieve the goals that the General Assembly may establish.

The legislation now under consideration to include nuclear generation as a Tier III resource in the AEPS as proposed in Senate Bill 510 and House Bill 11 provides a cautionary example of this concern. I will be submitting more detailed testimony on House Bill 11 next week and will be happy to provide that testimony to your Committees.[1] Under Senate Bill 510, my Office has estimated that the annual cost to consumers is between \$422 million and \$506 million based on the floor and ceiling price proposed in Senate Bill 510. Over the first six year term of the proposal, between \$2.5 billion and \$3.0 billion of ratepayer funds would be paid to nuclear units without any showing of financial necessity. That is, without any showing of financial distress of a unit or the need for financial support to compete in the market place, between \$2.5 billion and \$3.0 billion of ratepayer dollars—residential, businesses and industry alike—would be transferred to the shareholders of these major generating companies. I have attached to my written testimony some charts prepared by my Office showing estimated customer impacts for average customers in the residential, small commercial, medium commercial, and industrial classes and the total dollar impacts by customer class. *See*, Appendix A, Customer Impact Charts Prepared by the Office of Consumer Advocate.

These ratepayer funds would be mostly paid to nuclear units that are already showing a profit in today's wholesale markets, and based on the PJM Market Monitor's analysis, have been profitable for most of the years since 2008, the date the analysis begins, and will be

[1] There are other concerns for ratepayers that I have identified with Senate Bill 510 beyond those discussed in this Testimony. I look forward to further discussions with the Committee as consideration of the Bill continues. By way of example, some issues that require further consideration include the fact that the nuclear subsidies are exempted from the requirement of competitive procurement and the least cost over time standard that applies to energy procurement and AEC procurement; there appears to be no reconciliation or adjustment for increasing market prices that might make the nuclear units more profitable; there is no time limit on the length of the program or further review; and the capacity payment provisions are premature and may be inconsistent with retail choice.

profitable through 2021. *See*, Appendix B, Net Revenue Analysis for PJM Region Nuclear Plants, *Monitoring Analytics State of the Market Report for PJM, March, 2019*. Only one Pennsylvania unit, TMI-1, a single station plant, is uneconomic in today's wholesale market. I have also attached to my testimony an analysis of the expected revenues of each Pennsylvania plant which includes the revenues that would be received by each unit in 2019 with a Tier III payment. *See*, Appendix C, Plant Analysis Prepared by the Office of Consumer Advocate.

It is important to remember that ratepayers have already paid over $11.2 billion in stranded cost (about $6.8 billion to $9 billion for nuclear assets) as we restructured our electric industry to move to a model that utilizes the competitive wholesale markets for supplying our electric generation. The ratepayers of Metropolitan Edison Company and Pennsylvania Electric Company, the original owners of TMI-1, paid $420 million in stranded cost for TMI-1 and an additional $231 million in stranded decommissioning costs for TMI-1 and TMI-2. *See*, Appendix D, Final Reconciliation of Stranded Cost for Metropolitan Edison Company and Pennsylvania Electric Company. This, of course, was the stranded portion, the amount that had not already been recovered from ratepayers through past rates and was not expected to be recovered in the competitive wholesale markets.

It should also be noted that for a number of years the market prices realized by the nuclear units were in excess of what was used to determine stranded cost. Pennsylvania used what is referred to as a "once and done" approach to stranded cost meaning that there was no true-up or reconciliation of the estimated market prices to the actual market prices. When actual market prices exceeded the estimates and the nuclear units were more profitable in the wholesale markets than expected, those profits were retained by the nuclear plant owners. Looking at the PJM Market Monitor analysis for 2008, for TMI-1 that surplus was $40.5 million. *See*, Appendix B, Net

Revenue Analysis for PJM Region Nuclear Plants, Table 7-39, *Monitoring Analytics State of the Market Report for PJM, March, 2019*.

The changing nature of markets and market prices can also be seen in recent events. Since discussions have arisen around these issues in 2016, PJM energy prices have increased by 30% and PJM has undertaken numerous initiatives designed to increase both capacity prices and energy prices to better reflect the value and attributes of a diverse array of generation resources.[2] These initiatives will result in higher revenues to generation resources and higher prices paid by all consumers.

That brings me to the question of expansion of the AEPS, and the broader policy question of how best to achieve the goal of ensuring a safe, reliable, environmentally sustainable and diverse electric grid for the benefit of consumers at reasonable cost.

Your Committees have taken an important step in moving the discussion toward a more comprehensive look at our energy future. I think it is critical that we clearly identify our specific long-term energy goals, determine to what extent the costs of achieving those goals properly lies with Pennsylvania utility ratepayers, and ensure that the costs of achieving the goals is commensurate with the benefits. What has been most talked about recently is the need to achieve the environmental goal of reducing carbon emissions from our electric generation sector. While there are certainly other environmental, societal and public policy goals that must be considered, the environmental goal of reducing carbon emissions from our electric generation resources seems to cross over many of the initiatives that have been presented. In my view, we should first look to sound market-based mechanisms to achieve the environmental goals related to energy production

[2] I would note that the projected increases in capacity and energy prices resulting from modifications to PJM rules relate to the estimated value of the resources to the grid and do not include any valuations associated with environmental attributes. In addition, to the extent generating plants subject to RGGI represent the marginal generating resource, the RGGI costs on a per-MWh basis are reflected in the PJM wholesale market.

that the General Assembly seeks to achieve. If, for example, the reduction of carbon emissions from electricity production is the goal that Pennsylvania seeks to achieve, there are several well-tested market mechanisms to achieve this goal, many of which have been used to control other pollutants such as SO_2 and NO_x.

As a fully restructured state that is located within PJM, Pennsylvania is well-situated to implement a market-based approach to carbon emission reduction in an economically and environmentally sound manner.[3] Market mechanisms, such as setting a price on carbon or establishing a cap and trade program such as by joining the Regional Greenhouse Gas Initiative (RGGI) are two possible approaches. In the long term, market mechanisms should result in the most efficient and least cost solutions to achieving our goals, as well as foster innovation.

As I mentioned, RGGI is one such market mechanism that operates within PJM's footprint and is designed to limit carbon emissions from power plants. RGGI was launched in 2009, after the original enactment of the AEPS in 2004. RGGI members include six New England states, New York, Delaware, and Maryland. New Jersey is in the process of re-entering RGGI and Virginia is in the process of joining RGGI. By 2020, four states in PJM that surround Pennsylvania, as well as New York in the NYISO, will be participating in RGGI. Most importantly, while joining RGGI would increase energy prices and subsequently bills for ratepayers in Pennsylvania, the proceeds from the auction of emission allowances are returned to the state and can be used for a number of purposes, including reducing ratepayer bill impacts, supporting energy efficiency or renewable resources, and supporting affected communities. This

[3] PJM has recently published a White Paper entitled *Advancing Zero Emissions Objectives Through PJM's Energy Markets: A Review of Carbon Pricing Frameworks* examining opportunities to implement carbon pricing on a regional and sub-regional basis. https://www.pjm.com/~/media/library/reports-notices/special-reports/20170502-advancing-zero-emission-objectives-through-pjms-energy-markets.ashx. This was recently followed by a PJM Opportunity Statement and Issue Charge on this topic. See, https://pjm.com/-/media/committees-groups/committees/mrc/20190425/20190425-item-04-carbon-pricing-problem-statement.ashx; https://pjm.com/-/media/committees-groups/committees/mrc/20190425/20190425-item-04-carbon-pricing-issue-charge.ashx.

type of win-win solution should be the type of approach we should consider in meeting our environmental goals related to electricity production.

It is possible that in the short term, market-based solutions such as a price on carbon or a cap and trade approach such as RGGI may not fully close the gap in ensuring that necessary resources are available to achieve our goals. Some resources may need further market support or technological development in order to compete in wholesale competitive markets. In that instance, approaches such as transparently demonstrated need-based support for certain financially distressed units and enhanced portfolio standards that are targeted to closing the gap in market development for innovative resources or technology not supported yet by the markets may be needed. These mechanisms, though, should be closely evaluated to ensure that the tradeoff between costs and benefits is justified, and that only the level of support needed to achieve the clearly established goals is provided. These mechanisms should also be time-limited and re-evaluated on a periodic basis throughout the program to ensure that they are still needed and justified.

I thank you again for having me here today. I look forward to working with your Committees as we consider a comprehensive energy policy for Pennsylvania and consider the impacts on consumers.

APPENDIX A

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Pennsylvania Office of Consumer Advocate

Customer Impact Analysis of Senate Bill 510 of 2019

(Dollar Impact)

Customer Class	Annual Usage (1) MWh	Annual Impact RY 2019 $6.96/MWh Tier III AEC (2) (0.348 cents/kWh)	Annual Impact Ceiling $7.30/MWh Tier III AEC (3) (0.365 cents/kWh)	Annual Impact Floor $6.08/MWh Tier III AEC (4) (0.304 cents/kWh)
Residential	49,140,470	$171,008,836	$179,362,716	$149,387,029
Commercial	40,621,398	$141,362,465	$148,268,103	$123,489,050
Industrial	47,764,314	$166,219,813	$174,339,746	$145,203,515
Other	1,184,867	$4,123,337	$4,324,765	$3,601,996
Total (First Year Impact)	138,711,049	$482,714,451	$506,295,329	$421,681,589

Total (Based on Impact of Initial Six Year term)	Six-year Impact RY 2019	Six-year Impact Ceiling	Six-year Impact Floor
	$2.90 billion	$3.04 billion	$2.53 billion

(1) MWh consumption, by class, is for Calendar Year 2017 and is the sum of sales, by class, for Pennsylvania's 11 electric utilities. Source: Pennslyvania Public Utility Commission, *Electric Power Outlook for Pennsylvania 2017-2022*, August 2018, p. 20, Table 6. To calculate Reporting Year costs, it was assumed that CY 2017 sales levels, by class, would remain unchanged.

(2) Reporting Year (RY) is June1 through May 31. $6.96/MWh Tier III AECs price based on calendar year 2018 Pennsylvania Tier I AEC forward prices for each week for reporting years 2019/2020, 2020/2021, and 2021/2022 as reported in *Spectrometer Reports*.

(3) The Ceiling Price is calculated as 60% of $12.16, the weighted average price paid for Tier I AECs by Pennsylvania suppliers as reported in the Public Utility Commission's *2017 Annual Report of Alternative Energy Portfolio Standards Act of 2004*, p. 43, Table 2.

(4) The Floor Price is calculated as 50% of $12.16, the weighted average price paid for Tier I AECs by Pennsylvania suppliers as reported in the Public Utility Commission's *2017 Annual Report of Alternative Energy Portfolio Standards Act of 2004*, p. 43, Table 2.

PENNSYLVANIA OFFICE OF
CONSUMER ADVOCATE

Pennsylvania Office of Consumer Advocate

Customer Impact Analysis of Senate Bill 510 of 2019

(Representative Customer By Class)

Customer Information	**Annual Usage (1)** kWh	**Annual Impact RY 2019 \$6.96/MWh Tier III AEC (2)** (0.348 cents/kWh) **(5)**	**Annual Impact Ceiling \$7.30/MWh Tier III AEC (3)** (0.365 cents/kWh) **(5)**	**Annual Impact Floor \$6.08/MWh Tier III AEC (4)** (0.304 cents/kWh) **(5)**
Average Residential Customer	10,200	\$35	\$37	\$31
Small Commercial (Example: Convenience Store)	380,000	\$1,322	\$1,387	\$1,155
Medium Commercial (Example: Big Box Retail)	1,000,000	\$3,480	\$3,650	\$3,040
Large Hospital/Medium Manufacturer	18,000,000	\$62,640	\$65,700	\$54,720
Industrial Customer/University Campus	200,000,000	\$696,000	\$730,000	\$608,000

(1) The kWh amounts are representative of statewide average usage for the type of customer. Annual impact amounts are rounded.

(2) Reporting Year (RY) is June1 through May 31. \$6.96 Tier III AECs price based on calendar year 2018 Pennsylvania Tier I AEC forward prices for each week for reporting years 2019/2020, 2020/2021, and 2021/2022 as reported in *Spectrometer Report.*

(3) The Ceiling Price is calculated as 60% of \$12.16, the weighted average price paid for Tier I AECs by Pennsylvania suppliers as reported in the Public Utility Commission's 2017 Annual Report of Alternative Energy Portfolio Standards Act of 2004, p. 43, Table 2.

(4) The Floor Price is calculated as 50% of \$12.16, the weighted average price paid for Tier I AECs by Pennsylvania suppliers as reported in the Public Utility Commission's 2017 Annual Report of Alternative Energy Portfolio Standards Act of 2004, p. 43, Table 2.

(5) The cents per kWh figure is derived by assessing the Tier III AEC price on 50% of the annual usage.

PENNSYLVANIA OFFICE OF
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Pennsylvania Office of Consumer Advocate

Customer Impact Analysis of Senate Bill 510 of 2019
(Residential Customer)

Customer Information (1)	**Annual Impact RY 2019 (2)**	**Annual Impact Ceiling (3)**	**Annual Impact Floor (4)**
Average Residential Heating Customer (Duquesne, PECO, PPL) Annual Usage: 12,800 kWh	\$45 (\$3.75/month)	\$47 (\$3.90/month)	\$39 (\$3.25/month)
Average Residential Non-heating Customer (Duquesne, PECO, PPL) Annual Usage: 8,000 kWh	\$28 (\$2.33/month)	\$29 (\$2.42/month)	\$24 (\$2.00/month)
Average Residential Customer (MetEd, Penn Power, West Penn) Annual Usage: 10,850 kWh	\$38 (\$3.17/month)	\$40 (\$3.33/month)	\$33 (\$2.75/month)
Average Residential Customer (Penelec, UGI) Annual Usage: 8,450 kWh	\$29 (\$2.42/month)	\$31 (\$2.60/month)	\$26 (\$2.17/month)

(1) kWh amounts are representative of the average usage of the type of residential customer for the identified utility. Utilities were grouped based on comparable residential monthly usage and dollar figures are rounded for ease of presentation.

(2) Reporting Year (RY) is June 1 through May 31. \$6.96/MWh Tier III AECs price based on calendar year 2018 Pennsylvania Tier I AEC forward prices for each week for reporting years 2019/2020, 2020/2021, and 2021/2022 as reported in *Spectrometer Reports*.

(3) The Ceiling Price (\$7.30/MWh) is calculated as 60% of \$12.16, the weighted average price paid for Tier I AECs by Pennsylvania suppliers as reported in the Public Utility Commission's 2017 Annual Report of Alternative Energy Portfolio Standards Act of 2004, p. 43, Table 2 and applied to 50% of the usage.

(4) The Floor Price (\$6.08/MWh) is calculated as 50% of \$12.16, the weighted average price paid for Tier I AECs by Pennsylvania suppliers as reported in the Public Utility Commission's *2017 Annual Report of Alternative Energy Portfolio Standards Act of 2004*, p. 43, Table 2 and applied to 50% of the usage.

APPENDIX B

Net Revenue Analysis for PJM Region Nuclear Plants

From

Monitoring Analytics' State of the Market Report for PJM

Annual 2018

State of the Market Report for PJM

Volume 1:
Introduction

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

2018

3.14.2019

Table 7-39 Nuclear unit surplus (shortfall) based on public data: 2008 through 2018

	ICAP	Surplus (Shortfall) ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$26.1	$6.0	$10.1	$8.5	($3.4)	$1.4	$11.5	$2.9	($0.8)	$2.1	$11.5
Braidwood	2,337	$24.7	$2.2	$6.0	$3.0	($6.3)	($2.6)	$7.0	($1.5)	($3.6)	($2.0)	$3.5
Byron	2,300	$24.2	($1.5)	$3.0	($0.9)	($9.5)	($3.7)	$4.7	($6.5)	($10.0)	($3.2)	$3.3
Calvert Cliffs	1,708	$60.1	$20.3	$28.1	$17.6	$4.2	$14.1	$31.1	$13.7	$6.7	$5.6	$13.9
Cook	2,069	$28.9	$6.7	$11.0	$8.4	($3.7)	$1.3	$10.1	$2.4	($1.0)	$1.1	$6.6
Davis Besse	894	NA	NA	NA	NA	($13.4)	($7.0)	$6.4	($1.9)	($4.8)	($8.9)	($2.2)
Dresden	1,797	$25.4	$2.8	$7.2	$4.1	($5.4)	($1.1)	$8.9	($0.0)	($2.0)	($0.6)	$4.6
Hope Creek	1,172	$53.5	$16.6	$24.1	$16.5	$2.2	$11.9	$25.6	$5.9	($2.7)	$0.9	$9.5
LaSalle	2,271	$24.6	$2.2	$6.0	$3.0	($6.2)	($1.9)	$7.5	($1.2)	($3.9)	($2.3)	$3.6
Limerick	2,242	$53.7	$16.7	$24.3	$16.3	$2.3	$11.7	$25.3	$6.1	($2.6)	$1.1	$9.7
North Anna	1,892	$51.8	$14.4	$25.1	$16.5	$0.1	$5.7	$23.0	$10.6	$2.6	$4.3	$13.6
Oyster Creek	608	$47.1	$8.0	$15.4	$6.8	($8.5)	$2.7	$16.0	($5.1)	($11.9)	($10.2)	($1.1)
Peach Bottom	2,347	$53.3	$16.5	$23.7	$15.8	$2.0	$11.8	$25.1	$5.4	($2.9)	$0.8	$9.2
Perry	1,240	NA	NA	NA	NA	($13.4)	($6.4)	$5.3	($1.0)	($4.7)	($7.9)	$0.6
Quad Cities	1,819	$23.9	($0.7)	$2.0	($2.2)	($13.4)	($7.0)	$0.3	($8.0)	($9.9)	($3.9)	$1.9
Salem	2,328	$53.6	$16.7	$24.0	$16.5	$2.2	$11.8	$25.5	$5.8	($2.8)	$0.8	$9.5
Surry	1,676	$48.6	$13.5	$23.8	$16.0	($0.2)	$5.1	$21.4	$10.4	$2.2	$4.1	$13.6
Susquehanna	2,520	$46.6	$14.8	$22.0	$15.8	$1.1	$10.6	$24.2	$5.9	($2.3)	$1.2	$7.6
Three Mile Island	803	$40.5	$6.1	$12.9	$4.2	($9.9)	$0.4	$13.3	($7.2)	($12.7)	($10.6)	($4.9)

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2019, 2020 and 2021 and known capacity market prices for 2019, 2020 and 2021. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values.

Table 7-40 shows PJM energy prices (LMP), capacity prices (BRA), and annual fuel, operating and capital expenditures for the 2019 through 2021 period. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[53] Forward prices are as of January 2, 2019. The capacity prices are known based on PJM capacity auction results.

Table 7-40 Forward prices in PJM energy and capacity markets and annual costs[54]

	ICAP	Average Forward LMP ($/MWh)				BRA Capacity Price ($/MWh)			2017 NEI Costs ($/MWh)		
	(MW)	2019	2020	2021	2022	2019	2020	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$34.32	$33.37	$31.58	$30.38	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Braidwood	2,337	$27.29	$26.53	$25.13	$24.12	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Byron	2,300	$27.27	$26.51	$25.11	$24.10	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Calvert Cliffs	1,708	$34.61	$33.88	$32.07	$30.81	$5.26	$3.80	$4.86	$6.44	$18.46	$5.99
Cook	2,069	$30.93	$29.94	$28.36	$27.22	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Davis Besse	894	$33.44	$32.39	$30.69	$29.47	$5.25	$3.57	$5.45	$6.42	$27.32	$8.92
Dresden	1,797	$28.33	$27.52	$26.07	$25.03	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Hope Creek	1,172	$29.69	$29.27	$27.69	$26.60	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
LaSalle	2,271	$27.29	$26.53	$25.13	$24.12	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Limerick	2,242	$29.77	$29.33	$27.74	$26.66	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
North Anna	1,892	$34.19	$33.46	$31.67	$30.43	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Peach Bottom	2,347	$29.56	$29.13	$27.56	$26.48	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
Perry	1,240	$34.88	$34.02	$32.21	$30.95	$5.25	$3.57	$5.45	$6.42	$27.32	$8.92
Quad Cities	1,819	$25.86	$25.18	$23.84	$22.88	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Salem	2,328	$29.67	$29.24	$27.66	$26.58	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
Surry	1,676	$34.03	$33.29	$31.52	$30.28	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Susquehanna	2,520	$29.06	$28.66	$27.09	$26.05	$5.25	$3.80	$4.86	$6.44	$18.46	$5.99
Three Mile Island	803	$28.51	$28.12	$26.60	$25.56	$5.25	$3.80	$4.86	$6.42	$27.32	$8.92

53 Forward prices on January 2, 2019. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2018 data.

54 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>

Table 7-41 show the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, for the 2018 through 2021 period, on a per MWh basis. The fuel and operating costs are the 2017 NEI fuel, operating, and capital costs. Table 7-42 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor. Based on forward prices for energy and known forward prices for capacity, all but three nuclear plants would cover their annual avoidable costs on average over the next three years (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. The three plants together are 2,937 MW.

Table 7-41 Nuclear unit forward annual surplus (shortfall) in $/MWh[55]

	Surplus (Shortfall) ($/MWh)		
	2019	2020	2021
Beaver Valley	$8.68	$6.05	$5.39
Braidwood	$4.99	$3.67	$2.19
Byron	$4.97	$3.65	$2.18
Calvert Cliffs	$8.97	$6.79	$6.03
Cook	$5.29	$2.61	$2.16
Davis Besse	($3.97)	($6.70)	($6.52)
Dresden	$6.03	$4.66	$3.14
Hope Creek	$5.57	$4.97	$4.03
LaSalle	$4.99	$3.67	$2.19
Limerick	$5.65	$5.03	$4.08
North Anna	$8.55	$6.14	$5.48
Peach Bottom	$5.44	$4.83	$3.90
Perry	($2.53)	($5.07)	($5.00)
Quad Cities	$3.56	$2.32	$0.90
Salem	$5.55	$4.95	$4.00
Surry	$8.39	$5.97	$5.32
Susquehanna	$3.41	$1.56	$1.06
Three Mile Island	($8.91)	($10.74)	($11.20)

Table 7-42 Nuclear unit forward annual surplus (shortfall) ($ in millions)[56]

	Surplus (Shortfall) ($ in millions)		
	2019	2020	2021
Beaver Valley	$134.3	$93.5	$84.7
Braidwood	$106.4	$80.3	$51.7
Byron	$104.3	$78.6	$50.6
Calvert Cliffs	$131.0	$99.0	$89.3
Cook	$95.8	$48.4	$41.9
Davis Besse	($26.9)	($47.8)	($45.6)
Dresden	$97.3	$76.4	$53.8
Hope Creek	$57.9	$52.0	$43.3
LaSalle	$103.5	$78.0	$50.2
Limerick	$112.2	$100.5	$83.8
North Anna	$138.6	$99.3	$90.0
Peach Bottom	$113.4	$101.5	$84.1
Perry	($22.6)	($49.6)	($47.8)
Quad Cities	$61.3	$42.2	$20.9
Salem	$114.6	$102.8	$85.5
Surry	$120.5	$85.6	$77.6
Susquehanna	$77.7	$37.4	$28.2
Three Mile Island	($56.9)	($69.6)	($72.3)

Units At Risk

The definition of units at risk of retirement is units that are not expected to recover their avoidable costs from the market.

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover and are expected to continue to fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement particularly if the results are expected to continue.[57] Units that failed to clear the most recent capacity auction(s) are at increased risk of retirement if this result is outside the control of the plant owner and is expected to continue. The profile of coal and nuclear units that are not expected to cover their going forward costs over the next three years is shown in Table 7-43.[58] [59] These units are considered at risk of retirement.[60]

The analysis of coal units compares expected energy and capacity market revenues to ACR values and exclude APIR over the period 2019-2021. Bus level forward LMPs are based on forward prices with a basis adjustment for

55 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

56 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

57 FRR coal units, external coal units, and coal units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.

58 Avoidable costs for coal units are ACR values and exclude APIR.

59 For nuclear units, avoidable costs consist of fuel costs, operating costs, and capital expenditures.

60 Units expected to continue operations for reasons not directly related to market prices are not considered at risk of retirement.

APPENDIX C

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Pennsylvania Office of Consumer Advocate
Senate Bill 510 of 2019
Plant Net Revenue Analysis
(Initial Year Price)

Plant	Annual Generation at 77% Capacity Factor (1) (mWh)	MMU 2019 Net Revenue Surplus or (Shortfall)(2)	Proposed Tier III AEC Initial Year Price $6.96/ mWh	Surplus (Shortfall) after SB510 Subsidy (3)
Limerick (2,277 MW)	15,358,820	$112,200,000	$106,897,387	$219,097,387
Peach Bottom (2,785 MW)	18,782,684	$113,400,000	$130,727,481	$244,127,481
Three Mile Island (981 MW)	6,615,692	($56,900,000)	$46,045,216	($10,854,784)
		Exelon Subtotal	$283,670,084	$452,370,084
Beaver Valley (1,847 MW)	12,457,035	$134,300,000	$86,700,964	$221,000,964
		First Energy Subtotal	$86,700,964	$221,000,964
Susquehanna (2,596 MW)	17,510,539	$77,700,000	$121,873,351	$199,573,351
		Talen Subtotal	$121,873,351	$199,573,351

(1) Annual generation is calculated using nameplate capacity taken from the U.S. Department of Energy, Energy Information Administration, 2017 Form EIA-860 data, Schedule 3, Generator Data at the lower level of the capacity factor included in the proposed legislation (77%).

(2) Monitoring Analytics, LLC, PJM 2018 State of the Market Report, Table 7-42, "Nuclear Unit Forward Annual Surplus (Shortfall)," p.252

(3) Surplus (Shortfall) is calculated as follows: MMU 2019 Net Revenue + Proposed Tier III AEC Initial Year Price

PENNSYLVANIA OFFICE OF
CONSUMER ADVOCATE

Pennsylvania Office of Consumer Advocate
Senate Bill 510 of 2019
Plant Net Revenue Analysis
(Ceiling Price)

Plant	Annual Generation at 77% Capacity Factor (1) (mWh)	MMU 2019 Net Revenue Surplus or (Shortfall)(2)	Proposed Tier III Revenue Ceiling $7.30/ mWh	Surplus (Shortfall) after SB510 Subsidy (3)
Limerick (2,277 MW)	15,358,820	$112,200,000	$112,119,386	$224,319,386
Peach Bottom (2,785 MW)	18,782,684	$113,400,000	$137,113,593	$250,513,593
Three Mile Island (981 MW)	6,615,692	($56,900,000)	$48,294,552	($8,605,448)
		Exelon Subtotal	$297,527,531	$466,227,531
Beaver Valley (1,847 MW)	12,457,035	$134,300,000	$90,936,356	$225,236,356
		First Energy Subtotal	$90,936,356	$225,236,356
Susquehanna (2,596 MW)	17,510,539	$77,700,000	$127,826,935	$205,526,935
		Talen Subtotal	$127,826,935	$205,526,935

(1) Annual generation is calculated using nameplate capacity taken from the U.S. Department of Energy, Energy Information Administration, 2017 Form EIA-860 data, Schedule 3, Generator Data at the lower level of the capacity factor included in the proposed legislation (77%).

(2) Monitoring Analytics, LLC, PJM 2018 State of the Market Report, Table 7-42, "Nuclear Unit Forward Annual Surplus (Shortfall)," p.252

(3) Surplus (Shortfall) is calculated as follows: MMU 2019 Net Revenue + Proposed Tier III Revenue Ceiling

PENNSYLVANIA OFFICE OF
CONSUMER ADVOCATE

Pennsylvania Office of Consumer Advocate
Senate Bill 510 of 2019
Plant Net Revenue Analysis
(Floor Price)

Plant	Annual Generation at 77% Capacity Factor (1) (mWh)	MMU 2019 Net Revenue Surplus or (Shortfall)(2)	Proposed Tier III Revenue Floor $6.08/mWh	Surplus (Shortfall) after SB510 Subsidy (3)
Limerick (2,277 MW)	15,358,820	$112,200,000	$93,381,626	$205,581,626
Peach Bottom (2,785 MW)	18,782,684	$113,400,000	$114,198,719	$227,598,719
Three Mile Island (981 MW)	6,615,692	($56,900,000)	$40,223,407	($16,676,593)
		Exelon Subtotal	$247,803,752	$416,503,752
Beaver Valley (1,847 MW)	12,457,035	$134,300,000	$75,738,773	$210,038,773
		First Energy Subtotal	$75,738,773	$210,038,773
Susquehanna (2,596 MW)	17,510,539	$77,700,000	$106,464,077	$184,164,077
		Talen Subtotal	$106,464,077	$184,164,077

(1) Annual generation is calculated using nameplate capacity taken from the U.S. Department of Energy, Energy Information Administration, 2017 Form EIA-860 data, Schedule 3, Generator Data at the lower level of the capacity factor included in the proposed legislation (77%).

(2) Monitoring Analytics, LLC, PJM 2018 State of the Market Report, Table 7-42, "Nuclear Unit Forward Annual Surplus (Shortfall)," p.252

(3) Surplus (Shortfall) is calculated as follows: MMU 2019 Net Revenue + Proposed Tier III Revenue Floor

APPENDIX D

Metropolitan Edison Company

Docket No. R-00974008

Report on Actual Net Divestiture Proceeds and Reconciliation of Stranded Costs

January 31, 2000

Metropolitan Edison Company
Stranded Cost Adjustments
TMI-1
Schedule 5

To adjust the estimated stranded costs used in the Settlement from the sale of TMI-1 to the actual stranded costs.

Line No.	Description	TMI (A) (1)	(2)	(3)	Total (4)
1	Estimated net proceeds per settlement				$ 221,630,000
	Actual net proceeds from sale:				
2	Plant sales price		$ (11,500,000)		
3	Net effect of nuclear fuel payment		2,653,891		
4	Total proceeds		$ (8,846,109)		
5	Adjustments to sales price for turbine repairs		2,500,000		
6	Adjusted sales price			$ (6,346,109)	
	Book value of assets sold:				
	M&S Inventory	$ 14,932,974			
8	Plant	448,490,281			
9	Accumulated depreciation	(188,939,886)			
10	Net book value		$ 274,483,369		
11	DOE decontamination & decommissioning (B)		7,408,897		
12	Transaction costs(Non-employee)		723,280		
13	Employee related transaction costs (C)		3,640,000		
14	Total offsets to proceeds			286,255,546	
15	Phase 2 Stranded Costs (line 14 - line 6)			$ 277,409,437	
16	Retail allocation (line 18 x 99.395%)				275,731,110
17	Adjustment (line 16 - line 1)				$ 54,101,110

(A) No future payments from Amergen for market price adjustments are included. These are treated as CTC revenues when received. NPV amounts are estimated at $22 million.

(B) The 1992 Energy Policy Act established annual assessments on utilities owning nuclear plants to provide for funding for decontamination and decommissioning of DOE nuclear facilities ("DOE D&D"). The Act further required that for ratemaking purposes these charges be treated as a fuel expense. This liability has not been assumed by the buyer.

(C) Includes an estimated amount of $3,213,000 for employee severence

Pennsylvania Electric Company

Docket No. R-00974009

Report on Actual Net Divestiture

Proceeds and Reconciliation of Stranded Costs

January 31, 2000

Pennsylvania Electric Company
Stranded Cost Adjustments
TMI-1
Schedule 4

To adjust the estimated stranded costs used in the Settlement from the sale of TMI-1 to the actual stranded costs.

Line No.	Description	TMI (A) (1)	(2)	(3)	Total (4)
1	Estimated stranded costs per settlement				$ 105,480,000
	Actual net proceeds from sale:				
2	Plant sales price		$ (5,750,000)		
3	Net effect of nuclear fuel payment		1,316,823		
4	Total proceeds			$ (4,433,177)	
5	Adjustments to sales price		$ 1,250,000		
6	Adjusted sales price			(3,183,177)	
	Book value of assets sold:				
7	M&S inventory	$ 7,469,884			
8	Plant	225,288,802			
9	Accumulated depreciation	(105,597,493)			
10	Net book value		$ 127,161,193		
11	DOE decontamination & decommissioning (B)		3,704,449		
12	Transaction costs(non-employee)		361,640		
13	Employee related transaction costs (C)		1,820,750		
14	Total offsets to proceeds			133,048,032	
15	Phase 2 Stranded Costs (line 14 - line 6)			$ 128,614,855	
16	Retail allocation at 93.919%				120,793,785
17	Adjustment (line 16 - line 1)				$ 15,313,785

(A) No future payments from Amergen for market price adjustments are included. These are treated as CTC revenues when received. NPV amounts are estimated at $11.2 million.

(B) The 1992 Energy Policy Act established annual assessments on utilities owning nuclear plants to provide for funding for decontamination and decommissioning of DOE nuclear facilities ("DOE D&D"). The Act further required that for ratemaking purposes these charges be treatéd as a fuel expense. This liability has not been assumed by the buyer.

(C) Includes an estimated amount of $1,606,500 for employee severence