Prepared Testimony of

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Introduction

Good afternoon Chairman Roae, Chairman Matzie, and members of the House Consumer Affairs Committee. I am Gladys Brown Dutrieuille, Chairman of the Public Utility Commission (Commission or PUC).

The Commission thanks you for this opportunity to present testimony on House Bill 11 (HB 11). With the testimony I will convey a background on the electric generation market in Pennsylvania, a summary of the Commission's responsibilities established in HB 11, the Commission's stance on the bill, a review of the impacts of the bill, a cost analysis of the bill, and input to assist effective Commission implementation of the bill.

Background on Pennsylvania's Electric Market

Starting with the passage of The Electricity Generation Customer Choice and Competition Act of 1996 (Competition Act) and progressing through the Alternative Energy Portfolio Standards Act of 2004 (AEPS), the Commonwealth finds itself host to a vibrant electric generation landscape.

In 2018 Pennsylvania's generation fleet comprised 44,753 MWs, the largest amount of state installed capacity in the PJM Interconnection (PJM) footprint. When compared with a peak demand of approximately 30,000 MWs, Pennsylvania finds itself operating as a significant electricity exporter. Equally important is the present diversity of Pennsylvania's fleet. On an installed capacity basis, the state's fleet is comprised of approximately 38% natural gas, 26% coal, 22% nuclear, 4% oil, 5% hydro, 3% wind, and less than 1% solar.[1] Further, the retail competition market has been fairly successful, with over 32% of customers and 65% of load enrolled with an electric generation supplier (EGS).

Diversity of generation and competitive market forces have worked in tandem to facilitate reliable and economic electricity in the Commonwealth. This, in the Commission's view, is a positive story when compared with the pre-Competition Act electricity marketplace. At that time the state's electricity prices were significantly higher than the national average. Adjusting for inflation, the price for electricity in the PJM regional transmission organization (RTO) territory that Pennsylvania

[1] For 2018, PJM reported the following actual Pennsylvania dispatched generation on a MWh energy basis: 40% nuclear, 30% natural gas, 21% coal, 3% hydro, 2% wind, and less than 1% for all other remaining generation sources such as solar and battery.

belongs to has increased just slightly from $37.75 per MWh in 1999, to $40.13 per MWh in 2018.[2] Further, the amount of generation available above and beyond the projected peak demand, otherwise known as the reserve margin, was 22.9% for the 2017-2018 energy year.

Two main drivers have led to our state's current market success: first, the advent of natural gas production and corresponding natural gas fueled electric generation, and second, the fostering of competitive forces established by economic de-regulation of the electric generation market.

On the topic of natural gas fueled generation – breakthroughs in drilling technology have dramatically altered the economics of the commodity. As such, prices for natural gas have decreased from $8.86 per MMbtu in 2008, to $3.15 per MMbtu in 2018. This tectonic shift in natural gas prices facilitated an opportunity to increase the use of the resource as a fuel for electric generation. Therefore, multiple new facilitates have been constructed in the state totaling over 5,000 MWs of installed capacity, and there are more natural gas generation facilities planning to come into operation in the near future.

Since wholesale energy prices are unregulated, the competitive marketplace dictates the value of energy. The marketplace does this through a set of routine auctions. These auctions utilize the stack of offers which meet expected demand at the least cost while also meeting physical deliverability requirements. The pendulum shift of investment toward natural gas created a 'shake-up' in previous price formation dynamics. Historically, coal generation plants were the predominant price setters. The influx of cheap natural gas generation capacity transitioned the price setting economics to the natural gas fleet. This has been the case for a number of years.

Initially, this price shift largely affected coal plants and was a significant driver in the retirement of a large portion of the installed coal capacity. Now, the sustained effect of natural gas on electricity prices has begun to affect the economics of nuclear plants. Over recent years many of the nuclear plants in Pennsylvania have reported reduced profit margins or potentially lost money. Further, future prices indicate that some nuclear plants are expected to continue realizing smaller margins or negative margins. Case in point is the Three Mile Island nuclear generation facility (TMI). Since this facility's output is limited because it relies on a single reactor, its economics are more challenging.

[2] Monitoring Analytics 2018 PJM State of the Market Report.

This leads to the policy question the General Assembly is now setting out to address – should the General Assembly, in order to achieve certain public policy goals, intervene in this largely competitive marketplace or is it prudent to permit the current market design to run its course?

General Overview

The current AEPS is a market-driven program which requires electric distribution companies (EDCs) and EGSs to include as part of their retail electric sales certain sources of renewable generation. This is accomplished through the acquisition and retirement of Tier I (which includes, but is not limited to, solar photovoltaic, wind and low-impact hydropower) and Tier II (which includes, but is not limited to, waste coal, large-scale hydropower and municipal solid waste) alternative energy credits. As an amendment to the AEPS, HB 11 creates a new Tier III set of resources characterized by zero-emissions. Tier III includes a number of those resources already included in Tier I of AEPS, such as solar, wind, low-impact hydro, and geothermal while adding the additional qualifying resource of nuclear fission. The Tier III credit requirement is 50% of the Commonwealth's retail electric sales. Tier III credits would be valued based on the price of Tier I credits, with a hard floor and ceiling ultimately controlling the credit valuation.

In a manner which deviates from the design of Tier I and Tier II credit markets, which assigns liability for compliance to all the various load-serving entities (i.e. EDCs and EGSs) operating in the Commonwealth, under HB 11, EDCs are responsible for purchasing all of the Tier III credits, including those associated with EGS load, necessary to meet the 50% mandate for the entire electric demand in their respective service territories.

Further in contrast to the existing AEPS design, which permits all qualified facilities the opportunity to be certified for Tier I and Tier II credits, only a limited number of Tier III resources necessary to reach the 50% target would be qualified. The Commission would qualify the required number of generators through a ranking process which prioritizes each applicant's environmental benefits provided to the Commonwealth for a six-year period.

Finally, HB 11 includes a provision to permit AEPS qualified resources to opt-out of the local RTO's centralized capacity auction and thereby receive a substitute revenue stream through alternative means.

Impacts of HB 11

The Commission recognizes that there are a number of public policy variables being considered in the context of this proposed intervention. These impacts include but are not necessarily limited to those on local economies, taxes, jobs, environment, electric reliability, generation fleet diversity, wholesale electric prices, and customer electricity costs.

As an economic regulator it is incumbent on the Commission to monitor policies that have a material effect on electric customers' rates. To the contrary, it is not in the Commission's purview to offer official input associated with impacts on local economies, taxes, and jobs. Further, while the Commission does indirectly address policies pertaining to the environment, we respectfully defer discussion of this topic to the Department of Environmental Protection.

As to the topic of electric reliability, PJM has conducted studies to review the effects on grid reliability of the potential retirements of the Three Mile Island and the Beaver Valley nuclear generation facilities. Both studies have concluded that the retirement of TMI and Beaver Valley will not adversely affect the reliability of the wholesale electric grid. The retirement of Three Mile Island will require no further investment in transmission as a direct result, while the retirement of Beaver Valley will require upgrades to the transmission system located near or around that generation facility totaling approximately $180 million.[3] [4]

On the topic of generation diversity, the makeup of the existing Pennsylvania generation fleet is quite robust. As explained earlier, nuclear makes up about 22% of the installed capacity in the Commonwealth. The retirement of both Three Mile Island and Beaver Valley would reduce the nuclear installed capacity by roughly 2,800 MWs, or about 28% of Pennsylvania's nuclear fleet capacity. Holding all else equal, this would reduce the total share of the Pennsylvania nuclear fleet installed capacity from 22% to 16%.

The effect on wholesale power prices is also an important variable to analyze in this discussion. A 2018 Penn State University study analyzed the effect the

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[3] PJM spreadsheet detailing retirement study results, including those for TMI and Beaver Valley deactivation studies (see line 32 for TMI and lines 48 and 49 for Beaver Valley): http://www.pjm.com/~/media/planning/gen-retire/pending-deactivation-requests.ashx

[4] Some of these investments are not tied specifically to Beaver Valley's retirement, and the upgrades are already in progress.

retirements of Three Mile Island and Beaver Valley could have on these prices.[5] The study provided two results which are informative. First, if no new generation were to be built to replace these nuclear facilities, energy prices would rise in a range of 4% to 10% each year over the next three years. Conversely, if the lost nuclear capacity is replaced by natural gas fueled generation, which is the likely outcome, the wholesale energy prices would decrease in a range of 9% to 24% each year over the next three years.

Finally, the Commission has analyzed the overall credit cost for the Tier III program. The Commission's initial analysis of HB 11 results in an estimated minimum cost annually of $420 million and an estimated maximum annual cost of $550 million. These estimates are based on projected electric usage for the 2020 calendar year, the cost of AEPS Tier I compliance credits for the 2017 compliance year (the 12-month period ending May 31, 2017), and the price floor and ceiling formulas established in the HB 11.[6] For a residential customer using approximately 500 kWh the average monthly cost would range from $1.50 to $2.00 per month. For a residential customer using 2,000 kWh per month the cost would range from $6.00 to $8.00 per month. For businesses consuming substantially more electricity the costs would correspondingly be higher. For example, a large commercial customer using 200,000 kWh per month would see a range of a costs from $600 to $800 monthly.

Commission Implementation

HB 11 places a substantial amount of responsibility on the Commission to administer the Tier III program. HB 11 would require the Commission to: (1) solicit and evaluate applications for participation in the Tier III program; (2) select and rank qualified applicants; (3) establish the price of Tier III credits; (4) facilitate the transfer of credits to EDCs; (5) coordinate payments for the credits to the Tier III sources, and; (6) monitor Tier III compliance.

The unique design of HB 11 makes it challenging for the Commission to estimate the overall cost for administering the Tier III program. Specifically, the projected cost for the external administrator contract is challenging to gauge without issuing a formal request for information. Nonetheless, estimating the contract costs for an administrator to manage the Tier III requirements and projecting internal

[5] Impacts of the Retirement of the Beaver Valley and Three Mile Island Nuclear Power Plants on Capacity and Energy Prices in Pennsylvania – June 14, 2018.
[6] 2020 total estimated consumption of 138,223,522 MWh. 2017 reporting year Tier I AEPS credits averaged $12.16.

costs for analytical, legal, and administrative work results in an initial total Commission cost estimate of $2.5 million annually. We respectfully emphasize that these figures are initial estimates offered to provide gainful insight to this Committee at this time.

Commission Position

The Commission is neutral on HB 11. We recognize that the General Assembly must weigh various public policy objectives as it considers this proposed legislation. We envision our role as objective facilitators of the dialogue around this legislative process. Since the passage of the Competition Act the Commission has placed an increased focus on the energy arenas within our direct economic and service quality based regulatory authority – such as electric distribution costs and reliability metrics. Our role in the wholesale generation landscape is limited to general oversight to ensure that policy movements do not negatively affect Pennsylvania's competitive retail market, reliability or affordability.

To that end, the Commission's stance since the Competition Act was passed has been supportive of competitive wholesale markets insofar as they deliver reliable service at reasonable prices. Nonetheless, it is appropriate for the General Assembly to consider changes in the direction of policies from time-to-time, such as those included in HB 11.

Commission Input

The Commission respectfully wishes to shed light on a few important issues with the current draft of HB 11. Because the Commission is an economic regulator, we would be remiss in not pointing out that the legislation will provide considerable out-of-market revenues to all nuclear generation in the state, regardless of whether or not the plants require financial assistance above that provided by PJM wholesale markets. Based on information provided by the PJM Independent Market Monitor, only TMI is clearly financially troubled at this time.

Payment of Tier III subsidies to all Pennsylvania nuclear plants could result in higher capacity market payments by Pennsylvania customers should the Federal Energy Regulatory Commission (FERC) approve capacity market proposals filed by PJM. Additionally, a number of energy and ancillary service reforms are under consideration by PJM: energy price formation, fuel security, and resilience, which all have the potential to raise energy prices to the benefit of nuclear generators. These additional revenues would be additive to those provided under HB 11 and would ultimately be borne by ratepayers. Further, PJM has convened a stakeholder process to study how to incorporate various carbon pricing options into its market.

With regard to the Commission's administrative duties enumerated in HB 11, the Commission submits that HB 11 does not provide sufficient time to perform certain key functions. First, HB 11 permits no time for the Commission to complete an implementation proceeding. Ideally, the Commission would have six to nine months to complete a proceeding which provides detailed guidance to all interested stakeholders. This would allow for a more transparent and orderly implementation of the generator application rankings, the EDC funding mechanisms, publishing of the Tier III prices and Tier III credit requirements, and securing a contract for a Tier III administrator.

Also, HB 11 presently only permits the Commission 90 days to review and rank generator applications. This process includes determining that the applicant is zero-emitting, that it satisfies the interconnection and emissions requirements, that it meets the financial and ownership requirements, and ranking all applicants to determine which receive Tier III credits and which do not. We respectfully ask that this timeline be extended to 180 days.

Additionally, HB 11 establishes sequenced timelines for the transfer of and payment for Tier III credits. These include the following: 35 days for the transfer of all credits from Tier III resources to the to the program administrator, seven days for EDCs to purchase Tier III credits from the administrator, and finally, seven days for the transfer of the Tier III credit revenues from the administrator to the Tier III resources. The Commission submits that these timelines are untenable. First, it is unlikely that EDCs will have final billing quality usage data for the entire year within 35 days.[7] Availability of such billing quality usage data is vital to calculating accurate Tier III credit requirements. Equally important, the seven-day timelines for collection and disbursement of Tier III revenues would be extremely challenging given the dynamics associated with these tasks, and, the magnitude of dollars channeling through the program administrator. Therefore, the Commission seeks consideration of an extension of all three timelines, or, in the alternative, a design which the Commission (i.e. the administrator) does not act as intermediary for collection and

[7] Billing quality usage data is defined as data that has been sourced from an EDC's meter data management system and that has been verified, estimated, and edited.

disbursement of Tier III funds, but simply acts in an administrative role by determining the number of credits each EDC purchases and from which resource.

Finally, with regard to administration, HB 11 does not provide an explicit funding mechanism to support the Commission's budget. Given the breadth of responsibilities placed on the Commission in HB 11, we ask that this Committee give consideration of placing an explicit funding mechanism in the bill.

Closing

In closing, we hope that this testimony has helped frame a better understanding of Pennsylvania's electric market, the projected impacts of HB 11, and the Commission's enumerated responsibilities under the bill. HB 11 is a complex bill which represents a profound shift in energy policy for the Commonwealth. The Commission is happy to work with both Committees, the General Assembly as a whole, and the Governor to facilitate your thoughtful considerations and deliberations during this legislative process. The Commission offers itself as a resource in that regard. We look forward to a continued dialogue.