PENNSYLVANIA PUBLIC UTILITY COMMISSION
HARRISBURG, PENNSYLVANIA 17105

Re: Investigations into Default Service and PJM Interconnection, LLC. settlement reforms	**Public Meeting: January 17, 2019** **3007101-CMR** **Docket No.**

MOTION OF COMMISSIONER ANDREW G. PLACE

On September 15, 2007, the Commission established a default service policy statement applicable to customers who have not chosen an alternative electric generation supplier (EGS) or who contracted for electric energy that was not delivered. Over that 11-year period, a number of fundamental changes have occurred in Pennsylvania's retail electricity industry. Most notable is the continued deployment of smart meters capable of hourly or sub-hourly interval meter reads, and the development of mechanisms for the availability and sharing of this data to customer agents. According to current Electric Distribution Company (EDC) smart meter plans, most large EDCs in Pennsylvania should have fully functional smart meters by 2020.

Coincident with this installation of smart meters, EDCs are developing updated wholesale settlement procedures and integrated cost allocation methods for energy, capacity and transmission costs via actual hourly energy use, as adjusted for losses and other factors, as well as "tickets" assigned to individual customers based on allocation methods for capacity and transmission documented in each EDC's Attachment M-2 in the PJM Interconnection, LLC. (PJM) Tariff. A customer's Peak Load Contribution (PLC) ticket is used to allocate capacity costs to the load serving entity (LSE) of the customer. In Pennsylvania, the customer's LSE is either an EGS, chosen by the customer, or the default service provider (DSP), currently the EDC.

As an example of this interval meter-based allocation procedure used for PJM capacity tickets, PECO gathers the actual hourly meter readings of the customer at hour-ending normal PJM Regional Transmission Organization (RTO) peak time Eastern Time (ET) for each of the five days coincident with the highest PJM system peak hours, as determined by PJM from the previous summer. These loads include an "add-back" of energy curtailed as a result of load management initiatives or restrictions as identified by PJM. PECO then calculates a weather-normalized peak load for each of these five hours, taking into account the actual customer usage reading, actual versus normal peak weather, customer rate class, and losses. Lastly, to calculate the preliminary PLC, PECO averages the five resulting load values. This average load value is used to prorate PECO's total system PJM capacity costs to customers.

In a similar fashion, PECO also calculates a transmission capacity ticket for each customer. The transmission capacity ticket is often referred to as the Network Service Peak Load ticket, or NSPL ticket. In the case of PECO, the NSPL ticket calculation method is identical to the PLC ticket calculation. For other EDCs the capacity and transmission capacity ticket allocations can vary between the two. As an example, PPL uses the 5 weather-normalized RTO system peak hour customer usage when determining the PLC ticket, but uses the 5 annual actual PPL system peak hour customer usage from the previous year (not summer period, nor weather normalized) when determining the NSPL ticket.

Prior to installation of smart meters and associated data management systems, energy, capacity and transmission costs were allocated based on standardized profiles for similar customer categories. Such standardized profiles limited or muted translation of positive customer behaviors to positive customer benefits related to future avoided costs which would normally be rewarded in wholesale markets according to the wholesale allocation schemes for interval metered customers. "Positive customer behaviors" include avoiding usage during peak RTO and utility peak usage periods and shifting usage to lower usage periods.

With the installation of smart meters, the long-term benefits associated with positive customer usage behaviors can be flowed back to customers if changes in retail rate design for previously non-interval customers are more aligned with wholesale cost allocation methods. Absent a change in retail rate design for default service, such benefits will only flow to the wholesale LSEs, such as wholesale DSPs or EGSs. Without direct methods for rewarding customers in a timely manner for positive behaviors, customer responses to market prices will be stunted, or suboptimal.

An example of better symmetry between wholesale and retail pricing structures can be seen in Pennsylvania default service rates for existing large customers, which have had interval meters installed for many years. This rate design is often referred to as Hourly Price Service, or HPS. While the design of these rates varies somewhat between EDCs, they all price energy at the actual real time or day ahead Locational Marginal Price (LMP), while some allocate capacity and transmission costs based on actual tickets which reflect peak hour system usage. Such a rate design, or other default service rate design options with time of use components may better align wholesale cost allocation with retail cost allocation. To the extent wholesale cost allocation aligns reasonably well with true cost causation principles, then such a system would provide more rational pricing signals to minimize long term costs. To this end, I propose opening a proceeding to discuss how this Commission should mesh smart meter investments with smarter default service rates and smarter cost allocation methods.[1]

Lastly, PJM will be filing shortly to significantly alter energy and ancillary market pricing mechanisms which are likely to significantly shift costs from wholesale capacity markets to wholesale energy markets. Such a shift in market design may have an impact on optimal default service rate designs.

As a starting point, we should review if our wholesale cost allocation methods, as reflected in the Attachment M-2 in the PJM Tariff filed at FERC for informational purposes, are reasonably aligned with cost allocation. Often capacity costs are allocated based on the top 5 summer peak hours, since the PJM RTO is summer peaking in aggregate. Similarly, transmission costs are often allocated on the peak 5 hours, or even a single peak hour, either at the RTO level or EDC level. In analyzing this issue, I propose the following preliminary questions:

1. What number of peak hours should be averaged to determine an optimal basis for allocation of capacity and transmission costs to LSEs? Should we include consecutive peak hours, or just one hour per peak day?
2. Should selected hours be based on the RTO peak or the EDC peak usage periods for capacity and/or transmission cost allocation?
3. Should we examine seasonal cost allocators for capacity and/or transmission to incent lower usage during, for example, the summer and winter periods?
4. Assuming some reform is ultimately implemented, what transitional period should this Commission adopt, recognizing that existing contracts could, in theory, be affected by changes in wholesale cost allocation?

Additionally, I find it prudent to analyze how the growth in advance metering and settlement technologies may facilitate our application of the default service design requirements enumerated in Act 129. Given the wholesale cost allocation methods noted above, how can retail default service rates be better aligned with

[1] The focus of this segment of this investigation deals with basic default service rate design, not rate design reform for base delivery rates under consideration in Docket No. M-2015-2518883, nor TOU rate design options under Act 129.

wholesale cost allocation? As is apparent from the example above, this question is principally targeted at the previously non-interval customers with no access to HPS – more specifically residential and small commercial customers, generally smaller than 100kw. The current policy essentially charges customers a simple fixed kwh charge for energy, capacity and transmission. Unfortunately, while such a charge is easy to describe and understand, it does not align well with actual cost causation at the wholesale level. Recognizing that there are many principles of rate design, and, recognizing the statutory requirements under Act 129, I welcome comments on how Pennsylvania can begin the process of evolving default service retail rate design and structure given the new meter infrastructure and wholesale market design of the future.

As to energy related costs, I welcome responses to the following questions:

1. Should default service rates evolve to include Time of Use (TOU) structures, such as on and off- peak rates, super off-peak rates, critical peak pricing (CPP) periods, or peak time rebate structures? If so, what specific TOU structures do interested parties believe are most optimal, and why?
2. What other energy market structures should we consider?
3. What modifications or standardization should be considered with regard to the design of HPS rates for large customers?

As to the demand component of electricity supply service related to PJM capacity charges, I welcome responses to these additional questions:

1. Should we continue to have a simple, per kwh adder to the energy and ancillary supply price, as we do today?
2. Should we design a critical peak price to collect these PJM capacity costs from default service customers? If so, how should such a charge be designed and determined?
3. Should we switch to a demand charge equal to or similar to the PLC and NSPL tickets?
4. Should we switch to a demand charge with some other design feature, and if so, please describe the design element, and why this would be appropriate?

Lastly, what procurement changes, if any, should this Commission pursue? For example, how will the recommended changes in energy and capacity market supply pricing impact full-requirements procurement methods in use today? Additionally, the advancement of renewable wind and solar technologies have driven down the costs of clean energy resources, which raises the issue as to whether or not EDC default service plans should have a stronger long-term contract component. Previously, long term contracts for renewable contracts were often well above market. However, recent contracts for energy below $25/MWh may offer prudent hedges which could contribute to a portion of our default service portfolio. I welcome comments on the prudency of long-term contracts in today's evolving marketplace. Specifically, I would appreciate comments on the following questions:

1. What evidence is there in PJM markets that long term contracts can be obtained in PJM markets that offer cost-effective hedges relative to status quo default service plans?
2. Assuming prudent opportunities exist:
   - What type of RFP structure for energy or renewable attributes should be contracted for?
   - Is there an optimal length for such long-term contracts?
   - Is there an optimal amount of long-term contracting?
   - Should contracting be limited to resources in a certain geographical area, and if so, what geographical area? Discuss the legal and cost impacts of any geographically limited proposal.

Based on the feedback received, the Commission may propose to amend our default service regulations, default service policy statement, or issue other orders as appropriate. Given the extensive list of issues addressed above, I recommend that the Office of Competitive Market Oversight, Law Bureau and the Bureau of Technical Utility Services (Bureaus) guide the process for comments and stakeholder meetings and final recommendations regarding the issues outlined in this Motion. In addition, I recommend that comments be submitted to the Commission within 90 days of the entry date of this Order, and reply comments submitted within 30 days thereafter.

THEREFORE, I move that:

1. The Office of Competitive Market Oversight and Law Bureau draft an Opinion and Order consistent with this Motion.

2. Comments in response to the Commission's Order at this docket be filed no later than 90 days of the entry date of the Order.

3. Reply comments at this docket be filed no later than 120 days of the entry date of the Order.

4. The Office of Competitive Market Oversight, Law Bureau and the Bureau of Technical Utility Services are directed to convene stakeholder groups, if necessary, to discuss the submitted comments and other issues including any proposed changes to the Commission's Default Service Policy Statement at 69 Pa. Code at Section 1801, et seq. and/or regulations.

5. The Bureaus are directed to develop a recommendation to the Commission regarding wholesale cost allocation and default service rate design and procurement reforms no later than nine months of the entry date of this Order.

January 17, 2019 **Andrew G. Place, Commissioner**