COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Proposed Policy Statement Regarding Default Service and Retail Electric Markets	:	**Docket No. M-2009-2140580**

COMMENTS OF
CONSTELLATION NEWENERGY, INC. AND
CONSTELLATION ENERGY COMMODITIES GROUP, INC.
ON PROPOSED RULEMAKING ORDER REGARDING
DEFAULT SERVICE REGULATIONS

I. INTRODUCTION

On January 14, 2010, the Pennsylvania Public Utility Commission ("Commission") issued its *Proposed Rulemaking Order* in the above-docketed proceeding ("Proposed Order"),[1] as published in the Pennsylvania Bulletin on May 1, 2010.[2] The Proposed Order included the Commission's proposed *Default Service Regulations* ("Proposed Regulations") intended to implement provisions of *Act 129 of 2008*[3] ("Act 129"), and presented 16 issues (each a "Commission Issue") for interested parties' consideration and comment with respect to the

1 *Proposed Rulemaking Order in re: Implementation of Act 129 of October 15, 2008; Default Service*, Commission Docket No. L-2009-2095604 (issued Jan. 14, 2010) ("Proposed Order").

2 PA Bulletin, Doc. No. 10-772, 40 Pa.B. 2267.

3 *Press Release, Governor Rendell Signs Energy Conservation Bill to Save Consumers Millions on Electricity; Urges Legislature to Pass Rate Mitigation Bill*, Pennsylvania Office of the Governor (Oct. 15, 2008) (http://www.portal.state.pa.us/portal/server.pt?open=512&objID=2999&PageID=431162&mode=2&contentid=http://pubcontent.state.pa.us/publishedcontent/publish/global/news_releases/governor_s_office/news_releases/governor_rendell_signs_energy_conservation_bill_to_save_consumers_millions_on_ electricity__urges_legislature_to_pass_rate_mitigation_bill.html).

Proposed Regulations.[4] In accordance with the Proposed Order, Constellation NewEnergy, Inc. ("CNE") and Constellation Energy Commodities Group, Inc. ("CCG") (collectively, "Constellation") hereby submit their Initial Comments regarding the Proposed Regulations and Commission Issues posed therein.

In the event that the Commission or its Staff prepares a service list for this proceeding or otherwise requires additional information regarding the positions presented herein, Constellation identifies the following individuals:

David Fein
Vice President, Energy Policy
Constellation Energy
550 West Washington Blvd., Suite 300
Chicago, IL 60661
(312) 704-8499
David.Fein@constellation.com

Divesh Gupta
Senior Counsel
Constellation Energy
111 Market Place, Suite 500
Baltimore, MD 21202
(410) 470-3158
Divesh.Gupta@constellation.com

Christopher A. Lewis
Christopher Sharp
Blank Rome LLP
One Logan Square
Philadelphia, PA 19103
(215) 569-5793
Lewis@blankrome.com
Sharp@blankrome.com

Constellation applauds the Commission, its Staff and interested parties for their implementation to date of the important new Laws presented by Act 129, especially in light of their review and development, and the Commission's consideration and approval, of several new Default Service plans ("DSPs") proposed by electric distribution companies ("EDCs") since the new Laws' inception.

---

[4] Proposed Order at *Additional Issues*.

II. BACKGROUND ON CONSTELLATION

CCG and CNE are indirect, wholly-owned subsidiaries of Constellation Energy Group, Inc., a FORTUNE 500 North American energy company with several merchant subsidiaries in addition to CCG and CNE, including a regulated utility subsidiary, Baltimore Gas and Electric Company. CCG and CNE have been granted market-based rate authority by the Federal Energy Regulatory Commission ("FERC") and are buyers and sellers of wholesale electricity and capacity.

CNE is authorized to provide electricity and energy-related services to retail customers in Pennsylvania and thirteen other states, as well as the District of Columbia. CNE is a licensed Electric Generation Supplier ("EGS") in the Commonwealth, pursuant to 66 Pa.C.S. § 2809, and is registered to serve customers in most of Pennsylvania's larger EDCs' territories. CCG provides wholesale power and risk management services to wholesale customers (including, e.g., co-ops, municipalities, power marketers, EDCs and other large load serving entities), including through participation in Default Service procurements in the Commonwealth and similar processes throughout the United States, in both regulated and deregulated energy markets. CCG is a licensed participant in the PJM Interconnection, L.L.C. ("PJM") footprint.

As a potential supplier of both retail and wholesale power in the Commonwealth, the Proposed Order presents important issues which affect Constellation's ability to compete in Pennsylvania. These Initial Comments are based upon Constellation's extensive experience in the Commonwealth and in other jurisdictions regarding the establishment of rules and policies for retail markets, including wholesale procurements' effects and integration therein, and will ensure further development of the Commonwealth's competitive electric markets, providing enhanced benefits to consumers.

III. BACKGROUND ON ACT 129'S REQUIREMENTS FOR EDCS' DEFAULT SERVICE PROCUREMENT PLANS

The requirements for EDCs' structures for DSPs can be found in Act 129's revisions to Section 2807, *Duties of Electric Distribution Companies*, of Title 66 of the Pennsylvania Consolidated Statutes (66 Pa.C.S. § 2807). Overall, Act 129 requires that, for an EDC's DSP structure:

(1) "The electric power acquired shall be procured through competitive procurement processes and shall include" auctions, [requests for proposals ("RFPs")] and/or bilateral agreements"[5] ("**Requirement (1)**");

(2) "The electric power procured . . . shall include a prudent mix of" spot market purchases, short-term contracts and long-term purchase contracts "of more than four and not more than 20 years"[6] ("**Requirement (2)**"); and

(3) The "prudent mix" of supply contracts "shall be designed to ensure . . . adequate and reliable service . . . the least cost to customers over time . . . [and] compliance with the requirements of Paragraph (3.1)"[7] ("**Requirement (3)**").

Note that Requirement (3) includes only two sub-requirements, because its third sub-requirement is a reiteration of Paragraph (3.1), which is the section of Act 129 which describes the "prudent mix" referenced in Requirement 2 above. While Act 129 does not explain in further detail what may be necessary to meet the "adequate and reliable service" sub-requirement (herein referred to as "**Requirement (3)(a)**"), Act 129 does, in fact, provide a template for addressing whether a Default Service procurement structure meets Requirement (3)'s second sub-requirement (herein referred to as "**Requirement (3)(b)**") – i.e., whether the structure is likely to result in "the least cost to customers over time." For this Requirement (3)(b), Act 129 states specifically that:

---

5 Act 129 at 66 Pa.C.S. § 2807(e)(3.1).

6 Act 129 at 66 Pa.C.S. § 2807(e)(3.2).

7 Act 129 at 66 Pa.C.S. § 2807(e)(3.4).

> At the time the Commission evaluates the plan and prior to approval, *in determining if the default electric service provider's plan obtains generation supply at the least cost*, the Commission shall . . . make specific findings which shall include the following:
>
> (i) the default service provider's plan includes prudent steps necessary to negotiate favorable generation supply contracts.
>
> (ii) the default service provider's plan includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis. [and]
>
> (iii) neither the default service provider nor its affiliated interest has withheld from the market any generation supply in a manner that violates federal law.[8]

All together, then, with respect to Default Service procurement structures, Act 129 lays out **Requirements (1), (2), (3)(a) and (3)(b), <u>which includes</u> Requirements (3)(b)(i), (3)(b)(ii) and (3)(b)(iii)**.

IV. <u>CONSTELLATION COMMENTS</u>

<u>Commission Issue 1:</u> ***What is meant by "least cost to customers over time?"***

As discussed above, "least cost to customers over time" is Requirement 3(b) of Act 129's provisions for DSPs. The meaning of Requirement 3(b) can be found in the three Act 129 subparts identified above as Requirements 3(b)(i), (ii) and (iii), and codified at 66 Pa.C.S. § 2807(e)(3.7)(i)-(iii).

<u>Requirement 3(b)(i): Prudent steps necessary to negotiate favorable generation supply contracts.</u>

With respect to 3(b)(i), requiring "prudent steps necessary to negotiate favorable generation supply contracts," Constellation has consistently maintained that this is best accomplished through competitive procurements for wholesale supply, designed to maximize

[8] Act 129 at 66 Pa.C.S. § 2807(e)(3.7) (*emph. added*).

supplier participation. As a study submitted by the National Association of Regulatory Utility Commissioners ("NARUC") to FERC as part of the NARUC/FERC Competitive Procurement Collaborative explains:

> [c]ompetitive procurements can provide utilities with a way of obtaining electricity supply that has the 'best' fit to customers' needs at the 'best' possible terms . . . competitive procurements accomplish this goal by requiring market participants to compete for the opportunity to provide these services.[9]

When properly structured to allow for a broad potential pool of bidders, competitive procurements allow EDCs to obtain competitively-priced, favorable generation supply contracts.

Many of the Commission's recently-approved competitive procurements have indeed been structured properly in order to encourage favorable generation supply contracts. Whether through competitive RFP structures ("RFP Structures"), or through round-by-round, tick-down auctions ("Auctions") (collectively, "competitive bid processes" or "CBPs"), these procurements have incorporated important characteristics to encourage favorable outcomes, including, but not limited to:

- Providing a well defined role for the Commission in the Auctions and RFP Structures;
- Identifying and relying on independent third party overseers (e.g., NERA Economic Consulting);
- Assuring that the Auctions and RFP Structures are implemented in a non-discriminatory and highly transparent manner;
- Generally allocating to bidders appropriate risks as wholesale suppliers;
- Providing sufficient information to bidders, thereby allowing them to tailor their bids specifically to the requirements of each EDC's load and, in turn, promoting the most competitive wholesale prices for the benefit of each EDC's customers.

---

9 *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices*, the Analysis Group, Dr. Susan F. Tierney and Dr. Todd Schatzki, Commissioned by NARUC (issued July 2008) (http://www.naruc.org/Publications/NARUC%20Competitive%20Procurement%20Final.pdf) (the "NARUC Procurement Study") at p.i.

Pennsylvania's Default Service CBPs that have incorporated these types of characteristics, along with similar CBPs (relying largely on a variety of full requirements products ("FR Products")) in other jurisdictions, have resulted in prices that are reflective of the market.

In this way, the Auction and RFP Structures utilized in the Commonwealth have resulted in favorable fixed-price generation supply contracts being delivered to the EDCs and provided to retail customers that take Default Service from EDCs, bringing the advantages of a competitive wholesale marketplace to customers even if they are not taking service from competitive EGSs.

Requirement 3(b)(ii): Prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis.

With respect to the definition of Requirement 3(b)(ii), providing for "prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis," competitive structures again provide appropriate answers. In each case – whether for long-term, short-term or spot market purchases – it is best to rely on CBP structures designed such that winning bidders are able to be determined on the basis of "least cost" alone, eliminating the need to make determinations regarding bids based on other less objective criteria. As the NARUC Procurement Study explains:

> procuring products that meet standardized specifications . . . greatly simplifies the evaluation process by allowing for the selection of winning offers based on price terms alone. Identifying evaluation criteria that reflect the attributes of greatest importance will increases the likelihood of eliciting offers that best suit retail customers' supply needs.[10]

However, in order to encourage "least cost" purchases, contract terms must be designed in such a way as to promote the broadest participation by wholesale suppliers. With respect to credit, in particular, the NARUC Procurement Study points out that "it is important that

[10] NARUC Procurement Study at p.8.

collateral requirements are set to balance the utility's need to insure against default against the deterrence such requirements may have on supplier participation."[11]

In considering whether the Commonwealth's EDCs' DSPs are structured to attract potential bidders, then, the Commission should take into account the competitive procurement structures implemented for use by utilities in other states throughout the PJM footprint – the region in which all of Pennsylvania's largest EDCs will be located upon the Pennsylvania Power Company's ("Penn Power") transition out of the Midwest Independent System Operator's ("MISO") territory. As wholesale competitive procurement processes become more widespread as a best practice for EDC load procurement, particularly in PJM, wholesale suppliers have an increasing number of opportunities to compete to serve load under Default Service contracts. As these opportunities increase, wholesale suppliers will be required to carefully manage their portfolios and develop effective risk management strategies to provide cost effective service; this includes deciding which EDCs' procurements represent the best opportunities to serve load. This has become an increasing concern in the present global economic environment. Therefore, in order to ensure the most robust participation in the Commonwealth's Default Service CBPs – and, in turn, the "least cost generation supply contracts" – the Commission must be careful to compare and contrast Pennsylvania EDCs' and other jurisdictions' EDCs' Default Service CBPs' wholesale supply agreement requirements, especially (but not only) with respect to such agreements' collateral provisions. The Commission should make sure that Pennsylvania's EDC CBPs are at least equally attractive to potential bidders as such other jurisdictions' EDCs' competitive procurements.

11 NARUC Procurement Study at p.54.

As alluded to above, collateral provisions in wholesale supply agreements are particularly important when comparing Default Service CBP structures. The need for appropriate credit provisions for supply agreements is stronger than ever, as suppliers and the market require that risks be accounted for appropriately. In turn, the need to make Pennsylvania's CBPs as attractive to bidders as other similar procurements in the region is critical. To explain, credit ratings agencies will be carefully watching wholesale suppliers' risk exposure as their obligations under Default Service-type contracts increase. When a significant portion of a wholesale supplier's transactions are subject to counterparty credit risk, without the benefit of appropriate credit protection within the contract, as may be the case under EDC supply agreements, credit ratings agencies are likely to view the wholesale supplier as having more risk, and the supplier's credit ratings could suffer. If and when this occurs, wholesale suppliers' costs to serve load will increase and, in turn, customers' costs will increase. Moreover, if wholesale suppliers limit their own participation in the Commonwealth's CBPs in order to limit their exposure in supply agreements without the benefits of appropriate credit protection, customers will not receive the benefits of the most robust participation in the procurements, further increasing the chances that customers' costs may increase.

Furthermore, even if a Pennsylvania EDC does not suffer or otherwise face the possibility of a credit ratings downgrade, a wholesale supplier still must manage its credit risk due to exposure to such EDC without appropriate credit protections under the EDC's supply agreements. Suppliers' credit risks due to such an EDC's financial standing may be managed in one or both of two ways: the supplier may limit its participation in the EDC's CBPs, thereby deterring the most robust participation in the EDC's DSP, and/or the supplier may increase its bids to reflect the increased credit risk that it faces.[12] In either instance, consumers may face additional costs.

For these reasons, Constellation recommends that the Commission urge the Retail Markets Working Group (Docket No. M-00072009)[13] to develop "best-practice" documents that promote the most competitive processes for the procurement of wholesale Default Service supply for Pennsylvania's consumers in the near future. If best practices are designed and implemented, based on a comparison of CBPs and wholesale supply contracts utilized throughout PJM, Pennsylvania DSPs' competitive procurements, in this way, will assure that the least cost generation supply contracts are selected for products procured for a long-term, short-term and spot market basis.

Requirement 3(b)(iii): Neither the Default Service provider nor its affiliated interest has withheld generation supply in a manner that violates Federal law.

Act 129 appropriately defers to Federal laws when referencing Requirement 3(b)(iii), i.e., the consideration of whether a generator has withheld any supply from the wholesale market. DSPs—through reliance on wholesale supply from PJM and other interconnected markets, and through requirements that bidders maintain appropriate PJM qualifications and FERC

---

[12] When a supplier prepares its bids and knows that it will not have reciprocal credit provisions, as is currently the case under most of the Commonwealth's EDCs' supply agreements, it must consider the risk that in a market environment where prices have declined after the contracts are awarded, a declaration of bankruptcy by an EDC, due to credit downgrades and/or other business failures, may result in a bankruptcy court's rejection of the applicable supply agreements. That risk component may be factored into suppliers' bids and thus passed on to customers for each and every megawatt-hour of energy delivered. In contrast, rather than having to pay for such additional risks at all times, for all energy delivered, regardless of an EDC's financial standing, if the EDC's supply agreements included bilateral credit provisions, suppliers would no longer include costs for managing the credit risks due to changes in such EDC's financial standing, and consumers may pay additional credit costs only *if* the EDC's credit ratings actually are downgraded. While credit improvements to supply agreements (e.g., making improvements to have requirements similar to those in the supply agreements used in Maryland and Delaware) will help suppliers to *manage* the credit risks they face, they will not serve to *eliminate* such risks completely. Only bilateral credit provisions can appropriately remove such risks.

[13] The Commission initially established Docket No. M-00061960, *Standardization of Request for Proposal Documents and Supplier Master Agreements in the Context of Default Service*, to address these critical issues. By Secretarial Letter dated September 9, 2009, that docket was closed and its issues assigned to the Retail Markets Working Group. To date, these issues have not been addressed by the Retail Markets Working Group.

authorizations—can best assure that generators bidding on Default Service supply, including EDCs' affiliated interests, will be properly monitored and regulated to prevent withholding supply in a manner that violates Federal laws. The supply agreements utilized thus far in the Commonwealth typically contain these types of important provisions.[14]

FERC, with its jurisdiction over wholesale markets and suppliers, maintains broad authority over affiliate transactions as well as withholding of generation in any manner that violates Federal laws. Moreover, FERC possesses strong enforcement penalties, including the ability to assess a maximum penalty of $1,000,000 per violation for each day that such violation continues. FERC's enforcement authority – when relied upon in DSPs' CBPs and supply agreements – provides the necessary protections to ensure Pennsylvania DSPs' compliance with Requirement 3(iii).

<u>Commission Issue 2:</u> ***What time frame should the Commission use when evaluating whether a DSP's procurement plan produces least cost to customers over time?***

With respect to Act 129 only, no specific "time frame" exists for which the Commission must consider the "least cost to customers over time." However, as explained above, Act 129 already includes an explanation of how the Commission must determine whether a Default Service plan's procurements overall will produce the "least cost to customers over time."

---

[14] For instance, the Metropolitan Edison Company and Pennsylvania Electric Company supply agreements ("Met-Ed/Penelec Agreements") at Section 3.1(h) require that a Default Service Supplier:

> is in good standing as an LSE in PJM, is a signatory to all applicable PJM Agreements, and is in compliance with, and will continue to comply with, all obligations, rules and regulations, as established and interpreted by the PJM OI, that are applicable to LSEs as defined by the PJM Agreements . . . .

In addition, the Met-Ed/Penelec Agreements at Section 3.1(b) require that the DS Supplier represent that it:

> has all requisite power and authority to execute and deliver [the SMA] and to carry on the business to be conducted by it under [the SMA] and to enter into and perform its obligations hereunder, including satisfaction of all applicable FERC requirements . . . .

Nevertheless, it is important to recognize that Act 129's requirements have not been developed and passed by the Commonwealth in a vacuum; they occur and must be implemented in concert with the requirements of the *Electricity Generation Customer Choice and Competition Act* ("Competition Act").[15] The Competition Act today continues to require that the Commonwealth:

> transition from regulation to greater competition . . . to benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs.[16]

Thus, while the explicit language of Act 129 provides for a specific method through which the Commission must consider whether each DSP – for the full course of its term – meets the statutory definition of "least cost to customers over time," the Competition Act provides a broader directive as a measuring stick for the results of the Commission's and EDCs' actions and structures "over time" – i.e., they must "benefit all classes" by transitioning to "greater competition."

If by Commonwealth Law the Commission must balance the costs to customers against the benefits to such customers, then *over time* the policies and programs approved and implemented by the Commission must promote and lead to greater wholesale and retail competition. The "costs to customers" for the Commission's consideration may include not only prices paid by particular customers, but also the risks and the loss of opportunities faced by such customers. In order to promote competition, then, the DSPs approved by the Commission must not only allow for: (1) continued access to and promotion of retail markets – through retail market enhancements (such as those promoted in the Commission's *Opinion and Order* regarding the PPL Electric Utilities Corp.'s retail electric markets)[17] and active monitoring for

---

15 66 Pa.C.S. § 2802(14).

16 66 Pa.C.S. § 2802(7).

17 *Opinion and Order*, Commission Docket No. M-2009-2104271 (issued Aug. 6, 2009).

and removal of barriers to the continued development of customer choice and competition; but also for (2) well-tailored Default Service offerings which, for each customer class, reflect the status of competitive retail markets for such customers, respectively.

For instance, today, if one particular "EDC A" serves larger customers that have or are expected to have robust competitive retail market options and the ability to access such opportunities, then the plain-vanilla and appropriate Default Service product for such customers may be an hourly service procured directly from PJM's spot markets. For EDC A's smaller customers, however, at this time it is not advisable to subject them to the volatility of substantial spot market purchases; a "plain vanilla" back-stop product for Default Service for these smaller customers is better addressed through more stable FR Products with no more than five (5) percent of their supply, if any, based on spot market pricing. These product mixes may be considered each time that EDC A returns for approval of a new DSP.

Thus, in order to incur the least cost and obtain the most benefit, *over time* – a period not defined by a limited number of months or years – customers must be able to transition to access competitive markets and offers.

Commission Issue 3: ***To comply with the requirement that the Commission ensure that default service is adequate and reliable, should the Commission's default service regulations incorporate provisions to ensure the construction of needed generation capacity in Pennsylvania?***

The Commission can best assure "adequate and reliable" Default Service by requiring DSPs to rely on the PJM markets for procuring wholesale supply, and not by revising the Proposed Regulations to incorporate provisions that require and/or consider the construction of new generation capacity in the Commonwealth. Constellation urges the Commission to work closely with PJM (particularly upon Penn Power's transition out of MISO) to determine whether and to what extent generation capacity may be needed in the Commonwealth for any given period. PJM is the most appropriate entity to provide an assessment of the need for additional capacity, if any, and has the best tools to undertake its primary duty of monitoring and managing the reliability of the regional transmission system that serves Pennsylvania and all other states in the PJM footprint. With these tools, as PJM states, "PJM analyzes and forecasts the future electricity needs of the region . . . [and] ensures that the growth of the electric system takes place efficiently, in an orderly, planned fashion, and that reliability is maintained."[18]

The reliability of electric supply in Pennsylvania depends on reliability in the Mid-Atlantic Area Council ("MAAC") and East Central Area Reliability Council ("ECAR") regions more broadly. Electricity flows respect the laws of physics; the geopolitical bounds of the Commonwealth mean little in assessing how power flows across the interconnected interstate grid. To that extent, Constellation is not aware of whether PJM has the ability to affirmatively identify Pennsylvania's *actual*, rather than conceptual, share of any potential shortfall that may exist at any point in time. It could be that Pennsylvania's actual "share" of any potential shortfall is close to *zero* megawatts – i.e., it could be the case that, if PJM were to estimate a shortfall in the broader region at any particular point in the future, Pennsylvania would be expected in *actuality* to have total generation and import capability of a magnitude equal to or greater than the amount required to meet PJM's reliability test to serve the total load in the Pennsylvania sub-region (*i.e.*, indicating that a reliability event – where supply cannot meet Pennsylvania demand – is likely to happen on only one (1) day in 25 years (the "1 in 25 Test")).

While Pennsylvania is not an "island" that can be assured of reliability simply by passing the 1 in 25 Test, knowledge of whether Pennsylvania would meet the 1 in 25 Test for its own

[18] *See* PJM Website at http://pjm.com/about/overview.html.

load requirements for any particular period of time would certainly inform any need for and types of solutions. To explain, if it was the case that Pennsylvania's "share" of a hypothetical 500 MW shortfall was much less than a 'proportional share' among five states, then a CBP seeking, for instance, 100 MW (500 MW divide by five states) of capacity in Pennsylvania for a two to three year period may both: (1) saddle Pennsylvania's consumers with significant costs for additional capacity to account for shortfalls outside of Pennsylvania's borders; and (2) procure capacity that does little if anything to alleviate the *actual* perceived problem – *i.e.*, the capacity shortfalls in the greater five-state region.[19] If PJM perceives any shortfall in the future in the region serving Pennsylvania, Constellation urges the Commission to ask PJM at that time to confirm any actual, rather than conceptual, estimate of Pennsylvania's contribution to any such shortfall. This key issue highlights an important reason why it is inadvisable for the Commission to include provisions in its Proposed Regulations to accommodate the construction of new generation.

<u>Commission Issue 4:</u> ***If the Commission should adopt a provision to ensure the construction of needed generation capacity, how should the default service regulations be revised?***

<u>The Commission Should and Need Not Act Independently of Regional Solutions</u>

Constellation repeats its recommendation that the Commission refrain from adopting a provision in its Proposed Regulations requiring and/or considering the construction of new

[19] Note that this is not to say that other states must be responsible to procure capacity within their borders equal to or in excess of their respective loads. All of the Mid-Atlantic states are part of a codependent region, and benefit from being member states of PJM, the world's largest competitive wholesale electricity market administered by the independent system operator. One of PJM's primary functions is to ensure the reliability of its electric power system serving people in all or parts of Delaware, Illinois, Indiana, Kentucky, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, the District of Columbia and Maryland. All of its members rely on PJM to determine the best solutions across its footprint for local and regional reliability issues.

generation capacity. Constellation again asks the Commission to keep in mind that it must view reliability issues (if any) and any potential solutions through a regional lens rather than through a focus only on the Commonwealth of Pennsylvania. Pennsylvania must not believe that it can solve MAAC/ECAR reliability alone; any attempt to do so will increase costs to Pennsylvania ratepayers and undermine regional solutions that may be underway as well as any new solutions that may be under consideration by PJM. If Pennsylvania chooses to act independently, it may place on Pennsylvania ratepayers alone an expensive insurance hedge against the chance that a reliability issue may in fact occur and will not be averted by regional solutions.

As mentioned above, from a reliability perspective, Pennsylvania benefits immensely from its participation in PJM. PJM is responsible for ensuring the reliable operation of the electricity system in a multi-state region by managing transmission, generation and demand response assets. PJM explains that it:

> has responsibility for managing changes and additions to the grid so that future needs are anticipated, growth occurs in an orderly fashion and reliability is never jeopardized. The plan considers the growth and changes in the broad, multi-state region . . . . The decision to construct new electric generating plants or transmission lines is a serious undertaking. Such decisions cannot be made unilaterally, since these projects affect the overall configuration of the electric grid and the ability of the electric system to reliably deliver power to customers.[20]

In considering the reliability of energy supply for Pennsylvania consumers, the Commission should address the subject and any actions that affect reliability in the context of PJM and through PJM's regional planning process. This will assure the most effective and cost-efficient solutions, spreading the responsibility across the broader region, rather than placing it only on Pennsylvania's consumers. This is especially important if, as suggested above, the primary causes of a potential shortfall do not fall within Pennsylvania's borders.

---

[20] *See Backgrounder on PJM Interconnection* (http://www.pjmenergy.com/about/downloads/media-kit-backgrounder.pdf) at pp.3-4.

With respect to reliability, market-based approaches that place risks upon investors should be preferred over regulated structures such as mandatory EDC or state-issued RFPs that pass risks onto consumers. Competitive market participants are more able to manage increasing costs of construction, operation, fuel, environmental compliance and siting issues, for instance, than utilities'. More importantly, by relying upon competitive market participants to bear such risks, retail customers will be protected from such risks. Moreover, as noted above, Pennsylvania inextricably is part of a broader competitive market in PJM. The Commission should not dismiss PJM's reliability function, including its "backstop" function. The PJM Open Access Transmission Tariff ("OATT") states that:

> [t]he Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by: (a) lack of sufficient capacity committed through the Reliability Pricing Model Auctions; or (b) near-term transmission deliverability violations identified after the Base Residual Auction is conducted. These backstop mechanisms are intended to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The backstop mechanisms are based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources through Self-Supply or the Reliability Pricing Model Auctions.[21]

If use of PJM's backstop authority is necessary, then it would be deployed to solve a potential regional reliability problem and the costs would be shared regionally, as set forth in the PJM OATT. Such an outcome should be preferable to Pennsylvania as the costs of the regional solution would not be borne *only by* Pennsylvania consumers as may be the case under a Commonwealth- or Pennsylvania EDC-issued procurement. PJM – with its ability to oversee and analyze its entire footprint across states and regions – is better situated to find the most cost-efficient and cost-effective backstop solution(s) across the market. If the Commission were to

[21] PJM OATT at Attachment DD, Section 16.1.

fund new generation construction or other reliability solutions through Pennsylvania-only ratepayer-guaranteed arrangements, inevitably – as Pennsylvania is part of the broader PJM footprint – Pennsylvania customers would pay for increased reliability for other PJM states, establishing an inequitable precedent for assuring reliability.

The State of Connecticut provides a salient example of the benefits of relying on a regional transmission operator ("RTO") to develop the best solutions to maintain reliability in a situation. In its situation, rather than taking it upon itself alone, Connecticut relied on its regional transmission operator, ISO New England Inc. ("ISO-NE"), to evaluate the issue and provide a regional solution. ISO-NE explained in a December 2003 filing at FERC that:

> there currently are concerns with reliability in southwest Connecticut ("SWCT") that are expected to continue until upgrades are made to the transmission system in that sub-region . . . ISO-NE is concerned that the combination of electric load and operating reserve requirements in SWCT will exceed the Resources available for that sub-region. If existing generation and transmission is not sufficient to meet the needs of the sub-region, the result will be overloaded transmission lines, low voltages, or outages.[22]

To meet this need, ISO-NE as the RTO developed its own "Gap RFP" that was targeted to the specific problem that it identified in SWCT and for which costs would be allocated to the specific transmission customers in the region with the identified reliability concerns.[23] The SWCT Gap RFP was issued on December 1, 2003 for resources that were required as soon as June 1, 2004, six months later. Resources were contracted for the term of the identified shortfall and reliability needs were thus met.

---

[22] *Revisions to NEPOOL Market Rule 1 (Gap RFPs)*, FERC Docket No. ER04-335-000 (filed Dec. 23, 2003) ("ISO-NE 2003 FERC Filing") at p.2.

[23] *See* ISO-NE 2003 FERC Filing at p.3. Note that this gap procurement included municipal utilities not normally under the jurisdiction of the Connecticut Department of Public Utility Control.

Rather than undertaking any potential reliability matter on its own and forcing costs only on Pennsylvania ratepayers, the Commonwealth should rely on PJM to develop the most cost-effective regional solution for any identified regional reliability issue. In fact, PJM has evidenced that it monitors closely and analyzes continuously the issue of reliability in the region, and the Commonwealth and the Commission should be confident that PJM will continue to do so, and will develop and implement appropriate solutions, as necessary, in much the same way as ISO-NE handled reliability concerns in Connecticut.

Recommendations in the Event the Commission Nevertheless Includes Generation Construction Provisions in the Proposed Regulations for Default Service

Constellation urges the Commission to allow PJM to determine the appropriate solution to remedy any gap in reliability requirements in the future, as explained above. If the Commission nevertheless forges ahead with including in the Proposed Regulations for Default Service certain provisions for CBPs for new generation construction or other resources meant to address reliability ("Resource CBPs"), Constellation recommends that the Commission narrowly tailor such Resource CBPs to seek only products that are appropriate to the specific need that is identified, and that the costs for resources procured through the Resource CBPs be allocated only to appropriate transmission customers in the MAAC/ECAR regions.

First, with respect to the "type" of product that will be appropriate for a Resource CBP, it is necessary to analyze the specific "type" of need. It is important to note that the time period in question, if any, likely would be close in time to the procurements, and that the resources, if any, would likely be 'last resort' resources that are considered *necessary* for reliability. Therefore, a Resource CBP should be carefully designed to seek only those resources that can be deployed and operational in a short period of time, and that can be relied upon to in fact deliver the capacity which they commit through the Resource CBP. For this reason, Constellation first advises that if a Resource CBP is deemed necessary, then it should seek only resources that are more akin to those used to provide operating reserves rather than planning reserves. Whereas operating reserves can be dispatched on or off by the control area operator assuredly to avert an emergency, planning reserves represent resources that are known to exist, but may not be available with the same degree of reliability as operating reserves. In this way, a Resource CBP should first focus on resources capable of providing operating reserves such as:

- Existing generation that is not already committed to provide capacity for that time period;
- Existing generation that may be able to be up-rated relatively easily without triggering lengthy and complicated additional environmental reviews;
- Any other generation that can be constructed and/or be on-line within a very short time frame (*e.g.*, repowering of retired units); and
- Demand response resources under PJM dispatch control.

In addition, in order to provide greater confidence in such resources' commitment and ability to deliver when called upon, a Resource CBP should seek only those resources that are under the control of the system operator. For instance, if demand response resources are eligible, they should be akin to a PJM Demand Resource (DR) rather than an Interruptible Load for Reliability resource (ILR) – PJM DR represents demand response resources that can bid directly into PJM's capacity markets, and for which curtailments when called are mandatory.

Second, a Resource CBP should be narrowly tailored to seek resources only for the specifically identified timeframe of concern. For instance, if a gap is perceived only for Planning Year X, the Resource CBP should seek resources only for that 12-month period. Moreover, if there is a lower likelihood that the gap will remain during the first half of the following Planning Year Y (*i.e.*, after Planning Year X, but not for the entirety of the next Planning Year Y), then a Resource CBP perhaps should seek separate products for those months in Planning Year Y. In this way, any Resource CBP would intervene only to the extent necessary, and would not unnecessarily burden responsible ratepayers with costs extraneous to the immediate need.

Connecticut again serves as a clear illustration of these concepts. In Connecticut, however, ISO-NE perceived a potential gap that might have lasted for a longer period, over five years out from the procurement date. Thus, its products allowed greater variability in both resource type and timing. ISO-NE explained:

> The SWCT RFP invites any interested party to propose Resources to satisfy the subregion's reliability needs beginning June 1, 2004, and extending for as long as five years. Bidders may seek single or multiple year contract terms and need not be available by the June 1, 2004 start date to take part in the program. ISO-NE will select the most cost effective resources offered through the SWCT RFP. The following Resources are identified as eligible to provide this reliability service: new quick-start peaking capacity, incremental quick-start capability at existing resources; Demand Response Resources capable of 10-minute or 30-minute dispatch response; emergency generators capable of 10-minute and 30-minute dispatch response; and curtailment and load management projects that result in permanent load reductions during certain on-peak periods.[24]

With respect to the allocation of costs, Constellation again recommends that PJM, the Commission and market participants look to the process utilized in Connecticut if, despite the risks, the Commission deems a Gap RFP to be necessary for Pennsylvania. ISO-NE explained that:

> All costs paid under contracts awarded pursuant to a Gap RFP shall be allocated and charged each month to the Reliability Region affected by the Gap RFP . . . Accordingly, Transmission Customers in the Reliability Region with the reliability concerns will be the Customers who pay the costs of the RFP.[25]

---

[24] ISO-NE 2003 FERC Filing at p.2.

[25] ISO-NE 2003 FERC Filing at p.3.

Constellation similarly recommends that the costs of contracts awarded under a Resource CBP, if any, should be allocated only to the EDC zone(s) for which a shortfall is determined to exist. More specifically, the costs should be allocated through the distribution charges of the EDCs in those zones, in proportion to the load requirements for those EDCs' distribution systems.

Commission Issue 5: ***Which approach to supply procurement – a managed portfolio approach or a full requirements approach – is more likely to produce the least cost to customers over time?***

A full requirements approach – regardless of the length of wholesale supply contracts utilized within such approach (e.g., spot market products, three-month, six-month, one-year, two-year, or longer term products) – will best meet the requirements of Commonwealth Law, including Act 129's requirements to obtain the "least cost to customers over time," as well as those of the Competition Act. As explained above, it is important to keep in mind that "costs" to customers may include not only the prices paid by customers for Default Service supply, but the risks and lost opportunities they may face under a particular DSP. A full requirements approach will limit risks to customers by shifting them from an EDC to wholesale suppliers, while promoting opportunities for customers by providing well-defined, competitively-procured Default Service supply that provides appropriate benchmarks for comparisons to EGS product offerings.

As risks and costs to an EDC in Pennsylvania appropriately are passed on to its customers, it follows that the full requirements approach limits the risk to an EDC's customers by shifting them largely to FR Product suppliers. To explain, FR Products provide consumers with insurance for the duration of the contract by shifting risk to wholesale suppliers. The situation faced in 2008 by Wellsboro Electric Company ("Wellsboro") – a Pennsylvania utility procuring its Default Service requirements through a Managed Portfolio Approach – provided documented evidence as to the benefits of shifting such risk; Wellsboro faced a market "surprise" and had to seek permission from the Commission on January 30, 2008 to recover in excess of $2 million in additional congestion costs from its customers because of an unexpected congestion event.[26] Wellsboro's customers did not have the "insurance" provided by a full requirements supplier for such an event and, as a result, had to bear the burden themselves for the surprise rise in costs, as the Commission approved the pass through of such costs on February 28, 2008.[27]

A DSP relying on FR Products provides a proper balance by obtaining the most competitive prices for consumers, while appropriately placing risks such as volume risk (and virtually all price risks for fixed-price products, where such products are deemed appropriate for a DSP) on wholesale suppliers. Support for this notion comes from an important study on Pennsylvania's energy future by Dr. Susan F. Tierney, a nationally recognized energy policy expert, former Assistant Secretary for Policy at the U.S. Department of Energy, and former Commissioner at the Massachusetts Department of Public Utilities.[28] Dr. Tierney documents that, through competitive full requirements procurements, wholesale suppliers bring many benefits because of their abilities and skills.[29]

Requiring an EDC to retain personnel and expend resources to appropriately manage an energy portfolio of various supply products is an inefficient way to attempt to achieve

---

26 *See Joint Statement of Commissioner Kim Pizzingrilli and Vice Chairman James H. Cawley*, Commission Docket No. P-2008-202057 (issued Feb. 28, 2008) ("Wellsboro Feb. 2008 Decision") at p.1.

27 *See* Wellsboro Feb. 2008 Decision at p.1.

28 *See Pennsylvania's Electric Power Future: Trends and Guiding Principles*, Susan F. Tierney, Ph.D., Analysis Group (January 2008) ("2008 PA Market Study").

29 *See* 2008 PA Market Study at p.11 (stating that full requirements service "taps into the abilities and skills" of different wholesale market participants).

competitive and lowest cost Default Service prices for consumers. As an EDC's load must of course always be fully met (regardless of the type of procurement process the Commission adopts) at all hours, in order to manage its portion of load obligations (assigned through the Managed Portfolio Approach) most effectively, the EDC may at a minimum have to retain individual experts who understand and follow not only electric energy and other commodity markets, but also ancillary services, capacity and renewable products markets.

A diverse pool of wholesale FR Product suppliers – rather than EDCs themselves – provide the most cost-effective method of Default Service supply management for utility load. Under FR Product procurements, EDCs provide to potential bidders prior to procurements, and to winning bidders on an ongoing basis afterwards, all of the load data for their individual customer classes. Wholesale suppliers are specialists in the area of portfolio management, and have greater resources, expertise and ability to appropriately utilize this data to manage portfolios of supply at the least possible cost, by allocating the costs for their operations over much larger load obligations throughout the country. Moreover, such suppliers are able to draw from their substantial experience throughout PJM and in other jurisdictions to develop proprietary models of customer behavior and switching patterns, to refine these models, and to better analyze the local data provided by EDCs. These wholesale suppliers pass on the efficiencies they achieve due to their sophisticated risk management skills and experience in the form of more competitive bids for Default Service FR Products in a DSP's competitive procurements. Wholesale suppliers have already invested in, and continue to make significant investment in acquiring, experts in each specific type of market which makes up full requirements Default Service supply.

At Constellation, for instance, hundreds of employees are involved in the process of providing full requirements service to EDCs and customers around the country, serving tens of thousands of megawatts of various types of full requirements load from coast to coast. Constellation employs a team of seasoned portfolio managers for large regional portfolios that serve Constellation's customers' full requirements loads. Constellation must ensure that any transaction that goes into Constellation's entire portfolio of obligations is accounted for at the end of each day, and that requirements for the entire load are met continuously for every hour of every day of every week. A team of strategists continuously develops and improves computer models to keep track of all of the variable inputs that go into providing full requirements service; these strategists provide and analyze various scenarios that Constellation's portfolio managers may face. In addition, a fundamentals group constantly researches basic supply and demand in fuel and power markets in order to monitor macroeconomic trends that affect the costs of serving load. A 24-hour power trading desk trades power in the hour ahead, day ahead, and week ahead markets each day of the week, in order to help manage Constellation's supply portfolio. Moreover, power managers and traders monitor and trade in not only PJM's market, but also those in New York, New England and other markets throughout the U.S.; fuel managers do the same as fuel markets have direct effects on power markets. Similar resources focus on fuel oil, natural gas, coal, currency, emissions and renewable energy markets. Full-time meteorologists on Constellation's team continually monitor and predict the weather, so that Constellation's team can plan for weather effects on load requirements, and adjust supply accordingly. The task of meeting full requirements load supply additionally requires controllers, schedulers and dispatchers. Supporting all of these operations is a team of regulatory specialists and attorneys that monitor and participate in regulatory and legal activities which affect energy markets.

A wholesale supplier's greater expertise in these activities represents a valuable asset in evaluating and engaging in transactions for not only for complex hedges and other energy products, but for more common products in a portfolio such as block and spot market purchases. Increased levels of expertise and the ability to take on and manage a large portfolio's risks and responsibilities enable a wholesale supplier such as Constellation to provide significant competitive benefits over a smaller, less sophisticated market participant. Moreover, a wholesale supplier has the added expertise necessary to enter into more complex transactions which can provide additional appropriate management and hedging tools to further drive down costs.

Each of the tasks and positions described for Constellation's team plays an integral role in being able to drive down a wholesale supplier's costs of meeting load requirements and provide the most reliable, up-to-the minute improvements and adjustments to a portfolio of resources, from which all of the supplier's customers will benefit. For instance, it is unlikely that an EDC as portfolio manager will be able to take advantage of the incremental sophistication provided by a team of meteorologists. Absent such professionals, of course, no evidence exists to suggest that an EDC as portfolio manager will be able to predict the weather. Without the benefits of accurate and around-the-clock weather monitoring and predicting, if an EDC estimates a need and purchases block products ahead of time to meet its expected load for the summer, one can, for instance, evaluate a situation where there happens to be an unusually hot week in the middle of July. The EDC may face a situation where, because of the unusually hotter weather, homes and businesses are requiring *much* more electricity to run their air conditioners. If the EDC did not accurately predict how much load it would have in that week, because of its inability to accurately predict and react to the weather, it may face a situation where it needs to purchase in the spot market the additional supply that it requires at *high* electricity rates because, as demand for electricity increases around the region during a hot week, supply becomes constrained and prices for limited supply increase. The EDC's consumers will bear the burden of the costs of this inability to accurately predict and plan for the weather in real-time.

On the other hand, Constellation and other wholesale suppliers continually monitor and predict the weather as part of their portfolio management function and are able to react in real-time and adjust supply accordingly and efficiently, with an incentive to keep costs low.

The costs for all of the above types of expertise, however, are mitigated significantly by utilizing a well-developed infrastructure and spreading the overhead for such activities across a supplier's entire portfolio of tens of thousands of megawatts of supply obligations across the country, producing a far better result than a small team of people at a regulated EDC or its consultant. The costs for FR Product suppliers to provide such service for an EDC's customers will be highly constrained by the very competitive nature of this business, because wholesale suppliers throughout the market have operations similar in structure to those of Constellation, and will compete through a DSP's procurements to serve an EDC's Default Service load at the lowest cost. Given that costs of portfolio management under a DSP will be subject to downward pressure from competition to supply the load at the lowest possible costs, it is more likely that the costs of managing a portfolio under the DSP's proposed structure will inevitably be *less than* those under a plan that would use a Managed Portfolio Approach for the EDC's entire Default Service load, where the EDC as portfolio manager would have no economic incentive to drive down its costs. As a result, utilizing a DSP structure with a reliance on FR Products is likely to produce a far better result than a small team of people at a regulated EDC.

In addition, it is important to point out certain significant results from a recent analysis ("2010 Procurement Structure Analysis") conducted on behalf of Narragansett Electric Company d/b/a National Grid's ("National Grid"), and filed in the Rhode Island Public Utilities Commission's ('RIPUC") proceeding to consider National Grid's procurement structure for Standard Offer Service ("SOS"), Rhode Island's equivalent of Default Service.[30] The 2010 Procurement Structure Analysis provides an important and unique technical assessment based on advanced modeling, to compare and contrast "the relative costs and risks of different approaches to serve mass market [SOS] customers, and how different approaches could impact customers' [SOS] supply rates."[31] While the Analysis suggests that a Managed Portfolio Approach may, in fact, generally be cheaper than a FR Structure, it is cheaper only by the narrowest of margins – *roughly only $0.72/MWh.*[32] However, for this very limited benefit in cost due exclusively to the price for supply, consumers will be faced with *considerably more costs due to increased risks*.[33]

It is true, however, that wholesale suppliers bidding on FR Products may indeed place a certain value on the risk that they assume, for instance, for customer migration. The calculation for this monetization will depend on an individual wholesale supplier's perception of the level of such risk, its ability to manage the risk and its appetite for assuming the risk. By removing the potential for monetization and management of this risk by suppliers, a Managed Portfolio Approach takes the actual risk and places it on consumers. In other words, it is a zero sum game. Customers bear each "cost," either in the price or in the form of an assumed risk. This type of

---

30 *Analysis of Standard Offer Service Approaches for Mass Market Customers*, RIPUC Docket No. 4041 (submitted Jan. 22, 2010) ("2010 Procurement Structure Analysis")

31 2010 Procurement Structure Analysis at p.2.

32 *See* 2010 Procurement Structure Analysis at p.12 and p.15 (explaining that the FR Structure results in an expected SOS rate of only $0.72/MWh more than an alternative Managed Portfolio Approach).

33 *See* 2010 Procurement Structure Analysis at p.20.

shifting of risks directly to consumers fundamentally alters the nature of the Default Service product being provided by an EDC.

Proponents of a Managed Portfolio Approach often make claims that these monetizations and costs are exclusive to FR Products. This claim, however, represents the false assumption that products such as block products in a Managed Portfolio Approach will avoid (or else place on customers) most of the risks that are monetized in a FR Product. In fact, block products include all of the same risks – and, in turn, monetization of risks – as FR Products for items including, but not limited to, rising fuel costs, inflation, new energy taxes, market rule changes, market price changes prior to bid acceptance, and changes in credit standing. It follows that the only risk that may not be priced into the costs for block products is that of load variation, including variation due to customer migration. However, as explained above, if the fixed costs for the added benefits of FR Products – *including* for load variation – are highly constrained through the competitive nature of FR Product procurements, then it would be difficult to imagine that a Managed Portfolio Approach could result in more competitive prices than those achieved under the DSP FR Product procurements.

Detractors of full requirements structures also often suggest that a profit is added into a FR Product bid which is otherwise avoided when purchasing other products that may be procured under a Managed Portfolio Approach. In reality, any product that is purchased in the wholesale markets – e.g., whether a FR Product, a block product or a spot market purchase – will include in its price some level of profit that the supplier is willing and able to receive. Basic economic principles suggest that this is the case. When a seller sells a product – whether he is selling oranges, widgets or electricity – he seeks a return on his costs of producing the product. Basic economic principles also suggest that the price that a seller is "willing" to sell his product for will be constrained by the price he is "able" to sell his product for, so that in a competitive procurement, where only the lowest price from a pool of sellers is accepted, each seller will have an incentive to drive down the price at which he is "willing" to sell his product. This competitively constrained price for a FR Product will include a seller's perceived monetizations of risk as well as a profit on the overall FR Product. Depending on a supplier's perception of the level of risks, its ability to manage risks and its appetite for assuming risks, a supplier may have an ability to drive down further its underlying costs and overall prices. This especially is true for suppliers that are able to spread their costs across a large portfolio of supply obligations – if a supplier experiences lower revenue or a loss due to one of its obligations, for example, it is able to offset it against earnings across its entire portfolio of obligations. An EDC relying on a Managed Portfolio Approach has neither the competitive incentives to drive down its costs for managing risks nor the ability to hedge its obligations and costs across a broad, multi-regional portfolio.

Finally, it is important to keep in mind that all of these allegations against FR Products regarding relative costs appear not to be borne out when carefully analyzed – once again, the well-developed 2010 Procurement Structure Analysis suggests that the difference in consumers' prices for accepting the costs of increased risks under a Managed Portfolio Approach rather than placing such risks on suppliers through a FR Structure is roughly *only* \$0.72/MWh.[34]

[34] *See* 2010 Procurement Structure Analysis at p.12 and p.15 (explaining that the FR Structure results in an expected SOS rate of only \$0.72/MWh more than an alternative Managed Portfolio Approach).

<u>Commission Issue 6:</u> ***What is a "prudent mix" of spot, long-term, and short-term contracts?***

There exists no universal definition of specific percentages of each type of product which would represent a "prudent" mix of such contracts for each customer class, for each EDC. Rather, by requiring a "prudent" mix, Act 129 appropriately provides discretion to the Commission, EDCs and interested parties to review characteristics of each individual customer class of each separate EDC, respectively, on a case-by-case basis, in order to pre-determine and pre-approve what mix of product lengths would be "prudent" to meet such customer class' needs for Default Service supply, while continuing to promote competition and customer choice. As noted above with the example of EDC A, whereas if EDC A's larger customers today have or are expected to have robust competitive market options and the ability to access such opportunities, then the "prudent mix" of wholesale supply products for such particular customers may include only spot market purchases. However, for EDC A's smaller customers, at this time a different mix of wholesale supply contracts is "prudent" to include in such smaller customers' back-stop product for Default Service, including only very limited reliance on spot markets, if any. Such product mixes may be considered each time that EDC A returns for approval of a new DSP.

<u>Commission Issue 7:</u> ***Does a "prudent mix" mean that the contracts are diversified and accumulated over time?***

Where the Commission determines that for a specific EDC's particular class of customers it is prudent to provide a greater level of stability through a fixed-price Default Service, Constellation recognizes that there may be value in procuring the wholesale supply contracts for such fixed-price Default Service through staggered and laddered purchases over time. Where a portfolio of FR Products contains laddered contracts, that are blended in over time, consumers generally do not see dramatic shifts in market prices, either up or down, and are not subject to the price risk that may be inherent in purchasing all supply contracts at one point in time; such laddering may reduce volatility, while still providing a service which tracks overall market trends over time.

<u>Commission Issue 8:</u> ***Should there be qualified parameters on the prudent mix? For instance, should the regulations preclude a DSP from entering into all of its long-term contracts in one year?***

Please see Constellation's responses to Commission Issues 6 and 7. Act 129 appropriately provides discretion to the Commission, EDCs and interested parties to review characteristics of each individual customer class of each separate EDC, respectively, on a case-by-case basis, in order to pre-determine and pre-approve what mix of product lengths and timing of purchases may be "prudent" to meet such customer class' needs for Default Service supply, while continuing to promote competition and customer choice.

<u>Commission Issue 9:</u> ***Should the DSP be restricted to entering into a certain percentage of contracts per year?***

Please see Constellation's responses to Commission Issues 6 and 7. Act 129 appropriately provides discretion to the Commission, EDCs and interested parties to review characteristics of each individual customer class of each separate EDC, respectively, on a case-by-case basis, in order to pre-determine and pre-approve what mix of product lengths and timing of purchases may be "prudent" to meet such customer class' needs for Default Service supply, while continuing to promote competition and customer choice.

<u>Commission Issue 10:</u> ***Should there be a requirement that on a total-DSP basis, the "prudent mix" means that some quantity of the total-DSP default service load must be served through spot market purchases, some quantity must be served through short-term contracts, and some quantity must be served through long-term contracts?***

No. Please see Constellation's responses to Commission Issues 6 and 7. What is "prudent" should equate to what is "sensible" and "appropriate." Act 129 appropriately provides discretion to the Commission, EDCs and interested parties to review characteristics of each individual customer class of each separate EDC, respectively, on a case-by-case basis, in order to pre-determine and pre-approve what mix of product lengths and timing of purchases may be "prudent" to meet such customer class' needs for Default Service supply, while continuing to promote competition and customer choice.

<u>Commission Issue 11:</u> ***Should there be a requirement that some quantity of each rate class procurement group's load be served by spot market purchases, some quantity through short-term contracts, and some quantity through long-term contracts? In contrast, should a DSP be permitted to rely on only one or two of those product categories with the choice depending on what would be the prudent mix and would yield the least cost to customers over time for that specific DSP?***

With respect to the first question under Commission Issue 11, Constellation answers, "no," based on its answer to Commission Issue 10. In addition, Commission Issue 10 and the responses referenced therein would support an answer of "yes" to the second question under Commission Issue 11.

<u>Commission Issue 12:</u> ***Should the DSP be required to hedge its positions with futures including natural gas futures because of the link between prices of natural gas and the prices of electricity?***

No. For all of the reasons explained in Constellation's answers to Commission Issues 5 and 15, to the extent that the Commission deems it appropriate to provide a Default Service product that is more stable than hourly pricing for a particular customer class of a specific EDC, the best way to manage and hedge risks – including price risks – is by procuring full requirements supply products through competitive procurement processes.

<u>Commission Issue 13:</u> ***Is the "prudent mix" standard a different standard for each different customer class?***

Yes. Please see Constellation's responses to Commission Issues 6 through 11. Act 129 appropriately provides discretion to the Commission, EDCs and interested parties to review characteristics of each individual customer class of each separate EDC, respectively, on a case-by-case basis, in order to pre-determine and pre-approve what mix of product lengths and timing of purchases may be "prudent" to meet such customer class' needs for Default Service supply, while continuing to promote competition and customer choice.

<u>Commission Issue 14:</u> ***What will be the effects of bankruptcies of wholesale suppliers to default service suppliers on the short and long term contracts?***

As stated in Constellation's Response to Question 1, an ideal procurement structure for Default Service supply will include wholesale supply contracts which appropriately account for all risk, including but not limited to risks due to companies' financial standing. If properly structured to account for the financial standings of wholesale suppliers – including through carefully developed procurement and contract documents – any changes in such wholesale suppliers' characteristics should have no effects on contracts awarded through bidding under such Default Service plans.

<u>Commission Issue 15:</u> ***Does Act 129 allow for an after-the-fact review of the "cost reasonableness standard" in those cases where the approved default service plan gives the EDC substantial discretion regarding when to make purchases and how much electricity to buy in each purchase?***

Commission Issue 15 raises an additional important drawback of a Managed Portfolio Approach in comparison to reliance on FR Products. To the extent that the Commission determines that Act 129 supports a Managed Portfolio Approach, then Act 129 may or else *may need* to allow for after-the-fact reviews of the reasonableness of costs incurred under a Managed Portfolio Approach. To explain, proponents of a Managed Portfolio Approach also seem to support the notion that EDCs and the Commission should engage in 'market-timing,' making purchases in the market based on their evaluation of market price conditions; Constellation disagrees with such an approach.

Under this market-timing approach, an EDC would have the discretion to enter into contracts for Default Service supply at various times, depending on when it perceives market conditions to be "favorable." There are two fundamental flaws with an EDC using a market timing approach to procurement. First, there is no reason to believe that an EDC can outguess the market, which is what market timing is premised upon. Second, a market timing approach – where an EDC must use its "judgment to determine" when to make purchases – creates regulatory review and prudence issues that are not present in the full requirements procurement structure, and which would require that the Commission have the ability to review after-the-fact EDCs' decisions under a Managed Portfolio Approach.

Under a full requirements approach, each time the EDC accesses the market to make its purchases, one would expect that the offers it receives from prospective suppliers would be based on then-prevailing forward price curves for underlying products. Proponents of a Managed Portfolio Approach and market timing are, in effect, proposing that an EDC should look at forward prices at a given moment in time and make a decision about whether to procure supply at that time based on the EDC's view as to whether forward prices are going to move up or down from that level in the future. Under this approach, if the EDC "perceives" that forward prices are going to move up, it should lock in supply at that time. If the EDC "perceives" that forward prices are going to move down, it should wait.

The obvious problem with this logic is that the EDC has no way of knowing how forward prices will move. It may "perceive" that forward prices are going to move down, and postpone procurement, and find that prices in fact rise. Conversely, it may lock in at what it perceives is a good price, only to find after the fact that it has bought at the top of the market. The movement of future market prices is inherently uncertain, and there is no reason to believe that an EDC can outperform a procurement process that relies on a predetermined, periodic schedule for purchases.

An EDC is never likely to be in a position to outguess wholesale markets, nor should it try. The better approach is to avoid market timing and buy periodically, as is generally the case under the types of full requirements structures used today.

The market timing inherent in a Managed Portfolio Approach in this way creates regulatory review and prudence disallowance issues. If an EDC has discretion to make purchases based on its view of when there is a market "low," what happens after the fact if it is wrong, and forward prices dropped at some point after it bought? If the contracts can be disallowed after the fact because it is later learned that the EDC guessed wrong on the timing of its purchases, this could raise serious financial issues for the EDC, because of the magnitude of Default Service supply relative to the size of EDCs. This in turn raises the possibility that suppliers will add a risk premium for default risk, or require costly credit facilities to protect themselves. To avoid this, most advocates of market timing approaches propose that state commissions set up a process for a rapid, “real time” pre-approval when an EDC decides to access the market. While these regulatory pre-approval approaches may reduce or eliminate the ex-post disallowance risk, they can be cumbersome to administer. Moreover fundamentally, prudence pre-approval of the timing of when to access the market rests on the premise that the regulators are themselves in a position to evaluate an EDC’s market timing decisions – to say “yes, we agree the forward market is going to go up, so it is prudent to buy some supply now” or “no, we think you should wait because market conditions are going to become more favorable later.” Just as there is no reason why an EDC would have an inherent advantage in figuring out how to time the market (*i.e.*, when to buy “opportunistically”), relative to a process that relies on a fixed procurement schedule, there is no reason that a regulator would have such an advantage.

Any backward looking analysis that says “we could have saved money if we had waited or if we had bought sooner” is an exercise in hindsight. There is no way of knowing whether an EDC would have made the right guess at the time, given the inherent uncertainty in forward market price movements.

<u>Commission Issue 16:</u> ***How should the requirement that "this section shall apply" to the purchase of AECs be implemented. Section 2807(e)(3.5) states that " . . . the provisions of this section shall apply to any type of energy purchased by a default service provider to provide electric generation supply service, including energy or alternative energy portfolio standards credits required to be purchased, etc."***

Constellation understands the requirements of Section 2807(e)(3.5) identified in Commission Issue 16 to mean that each EDC must account in its Default Service plan for how it will meet the requirements of the Alternative Energy Portfolio Standards ("AEPS") Act.[35] This can be achieved, for instance, through including the requirement to meet the AEPS within the obligations placed on a wholesale full requirements product supplier. Regardless of the method in which an EDC proposes to meet its AEPS obligations within its Default Service plan, the Commission should ensure that such practice meets the requirements under both Act 129 and the Competition Act.

V. CONCLUSION

Constellation appreciates this opportunity to submit its Initial Comments to the Commission and looks forward to continued discussions on these and any new issues raised in the context of Default Service in Pennsylvania's competitive electric markets. Constellation is confident that its recommendations will promote continued development of the Commonwealth's competitive retail markets, for the ultimate benefit of Pennsylvania's consumers.

[35] 73 P.S. §§ 1648.1-.8.

Respectfully submitted,

Divesh Gupta
Senior Counsel
Constellation Energy
111 Market Place, Suite 500
Baltimore, MD 21202
410-470-3158
divesh.gupta@constellation.com

Christopher A. Lewis
Christopher R. Sharp
Blank Rome, LLP
One Logan Square
Philadelphia, PA 19103
(215) 569-5793
lewis@blankrome.com
sharp@blankrome.com

On Behalf of Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc.

DATED: June 1, 2010