DUQUESNE LIGHT STATEMENT NO. 3-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition Of Duquesne Light Company For Approval Of Default Service Plan For The Period June 1, 2015 Through May 31, 2017	**:** **:** **:**	**Docket No. P-2014-2418242**

REJOINDER TESTIMONY OF
NEIL S. FISHER

Dated: August 21, 2014

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I. Introduction

Q. Are you the same Neil S. Fisher who sponsored direct, rebuttal, and surrebuttal testimony in this proceeding?

A. Yes, I submitted direct testimony (Duquesne Light Statement No. 3) on April 24, 2014, with the Company's initial filing in this proceeding, rebuttal testimony (Duquesne Light Statement No. 3-R) on August 1, 2014, and surrebuttal testimony (Duquesne Light Statement No. 3-SR) on August 15, 2014.

Q. What is the purpose of your rejoinder testimony?

A. I will respond to surrebuttal arguments made by various interveners regarding the power procurement methods and the supply product portfolios used in Duquesne Light's proposed default service plan ("DSP VII" or "DSP VII Plan"). Specifically, I will respond to the Retail Energy Supply Association ("RESA") recommendation that Duquesne Light bid out spot market priced service for the Large Commercial and Industrial ("Large C&I") default service customers. Second, I will respond to the Citizens For Pennsylvania's Future ("PennFuture") recommendation to procure Alternative Energy Credits ("AECs") with a base amount fulfilled through ten and twenty year supply contracts. Third, I will respond to various surrebuttal comments made by RESA witness Hudson regarding price stability and the development of competitive markets as they relate to the term lengths of the products in the default service supply portfolio for the Residential and Small Commercial and Industrial ("Small C&I") customers. Fourth, I will respond to the

Pennsylvania Office of Consumer Advocate ("OCA") witness Estomin's proposal to include spot pricing in the Residential default service supply products.

Q. Please summarize your major conclusions.

A. The following are my major conclusions:

1. RESA's proposal to bid out spot market priced service for the Large C&I default service customers is unnecessary and should be rejected.
2. PennFuture's recommendation to procure AECs through ten and twenty year supply contracts should be rejected.
3. RESA's proposal to shorten the term lengths of default service supply products and to inject "hard stops" in the supply procurement process for Residential and Small C&I customers should be rejected.
4. The OCA's proposal to include spot pricing in the Residential default service supply products should be rejected.

Each of these conclusions is summarized below.

II. <u>RESA's Proposal to Bid Out Spot Market Priced Service for the Large C&I Default Service Customers is Unnecessary and Should Be Rejected</u>

Q. Does RESA make a specific proposal regarding how HPS would be bid out to a third party supplier?

A. No. Unfortunately, it is unclear at this stage of the proceeding what RESA's proposal is, what purpose it would serve, how it would impact customers on Hourly Price Service

("HPS"), or even how it could be implemented. At first, I thought RESA was suggesting that Duquesne Light bid out HPS to a third party supplier in a manner where wholesale bidders would be required to bid a "fixed price adder" to cover certain non-energy costs, which may include ancillary services, compliance with Alternative Energy Portfolio Standards ("AEPS"), capacity, and administrative costs for an extended period of time (e.g., a 12-month delivery period) similar to some other EDCs in Pennsylvania. But later in a discovery response, RESA recommends a very different approach, implying that the RFP could be based on the "existing pricing and cost collection structure" contained in Duquesne Light's Rider No. 9. RESA explains in its discovery response that "Duquesne [Light] would be in the best position to determine what, if any, changes are needed to the language in Rider No. 9 to effectuate this change."[1] While RESA's recommendation to bid out the existing pricing and cost collection structure contained in Duquesne Light's Rider No. 9 may sound simple, it is quite complicated and raises several very important questions, none of which have been addressed by RESA. In fact, a quick two-minute review of Duquesne Light's Retail Tariff Rider No. 9 should provide ample evidence of the complexity of the issues involved. (See Exhibit NSF-6.)

Q. Is RESA's recommendation intended to improve retail competition?

A. It is unclear. In surrebuttal, RESA witness Hudson states that even if it is true that Duquesne Light has one of the best retail access programs in the country for Large C&I customers in terms of switching and only a small portion of load remains on default service, this is beside the point. Based on RESA's surrebuttal testimony, RESA's Large

[1] Exhibit NSF-5, RESA Discovery Response to Duquesne Industrial Intervenors, Set I-3.

C&I recommendation to bid out HPS does not appear to be necessary or even motivated by the need to improve the competitive retail market.

Q. Is RESA proposing that the third party supplier bid a fixed price adder on top of the charges included in Rider No. 9?

A. It is unclear. Rider No. 9 passes through PJM spot energy costs, PJM capacity costs, spot ancillary service costs, alternative energy portfolio requirements, and other PJM direct charges. Basically, HPS supply costs are based on competitive wholesale market prices that are transparent and objective costs that are billed directly to retail customers.[2] If RESA is not proposing that the third party supplier bid a fixed price adder on top of the charges included in Rider No. 9, this raises a question of why a third party supplier would be interested in this type of arrangement, where the third party supplier could charge customers essentially spot market prices with no additional "compensation." In fact, a third party supplier could sell these supply products today in the competitive market without being an HPS supplier.

If RESA is proposing that the third party supplier bid a fixed price adder on top of the charges included in Rider No. 9, this raises a question of what benefits a third party supplier would provide HPS customers? Exactly what is it that the third party supplier would offer customers that they are not getting today?

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[2] As Duquesne Light witness Pfrommer describes in his rebuttal testimony, Duquesne Light's administrative costs related to providing HPS are largely tied to PJM interface and billing related costs that would remain even if a third party provided supply for HPS and Duquesne Light continued to do the billing and reconciliation.

Q. Is RESA proposing that the third party supplier continue to offer HPS customers the same scheduling flexibility they have today under Rider No. 9?

A. It is unclear. Rider No. 9 provides HPS customers with considerable flexibility, offering customers with the option of buying spot energy in either the day-ahead and/or real-time energy markets. Energy in a day-ahead schedule, subject to modification by each customer, is purchased in the day-ahead energy market with differences between the scheduled load and actual consumption settled in the real-time market. These purchases in the day-ahead and/or real-time energy markets are tracked on a customer-by-customer basis. It is unclear from RESA's proposal whether this purchasing flexibility could be continued if a third party supplier were to provide HPS.

RESA does not offer any specifics on how its proposal could be implemented or why third party suppliers would want to participate under the current program's terms and conditions. RESA also fails to take into account the current benefits provided to customers under Duquesne Light's HPS tariff.

Q. How do you respond to RESA's claim that its proposal will not impose significant costs upon customers because the product will be obtained via competitive bid to the lowest bidder?

A. Without a specific proposal from RESA, it is impossible to evaluate the potential impact on HPS customers. Further, if RESA is recommending that the RFP should be based on the existing pricing and cost collection structure contained in Duquesne Light's Rider No. 9, I am not aware of any EDC in Pennsylvania that has conducted such an RFP. Therefore, it is unclear what the cost implications would be for customers or whether any third party supplier would be interested in that type of solicitation. Finally, it should be noted that under RESA's proposal the EDC must also recover the added cost of conducting RFPs and still recover any administrative costs that Duquesne Light continues to incur to provide and bill for HPS.

Q. What is your response to RESA's claim that bidding out Large C&I load is consistent with Act 129?

A. I am not a lawyer, but Duquesne Light has been supplying HPS since DSP III, both before and after Act 129. The Commission has approved this service in DSP III, DSP IV, DSP V, and DSP VI. No party has made a credible claim that the retail market to serve Large C&I customers in Duquesne Light's service area has been harmed in any way under the current procurement approach. In fact, just the opposite is true. Duquesne Light arguably already has one of the best retail access programs in the country for Large C&I customers. And from RESA's perspective, I seriously doubt that RESA's proposal, whatever it turns out to be, could have more "market responsive" supply products than what Duquesne Light already has in place today.

Q. How do you respond to RESA's view that competitive forces should provide the service?

A. It is important to recognize that Duquesne Light already relies on standard competitive wholesale market products and passes through these costs directly to HPS customers. There is no opportunity for Duquesne Light to exercise market power or to manipulate prices. Competitive markets establish the energy, capacity and other supply cost components of the HPS rate, while other PJM administrative costs are directly passed through to customers.

Q. Mr. Fisher, do you have reason to believe that Large C&I customers want Duquesne Light to continue to provide HPS?

A. Yes. As I stated in my rebuttal testimony, when Duquesne Light initially proposed HPS during its DSP III proceeding, the Company proposed to rely on a competitive wholesale auction process, but the Company later agreed to supply this service in response to the comments provided by Large C&I customers (represented by the Duquesne Industrial Intervenors or "DII") and its desire to have Duquesne Light procure the supply directly from the PJM market. Several years later, at the request of DII, HPS was modified during a negotiated settlement process in DSP IV to allow Large C&I customers the flexibility of purchasing energy in day-ahead markets as opposed to just real-time markets.[3] I have worked on the development of the HPS product since its creation, and throughout that process, Large C&I customers have expressed a desire for Duquesne Light to provide this service, and have been actively engaged in the ultimate design structure of Rider No. 9. Duquesne Light arguably already has one of the best retail access programs in the country for Large C&I customers. Therefore, it is difficult to justify the added time and administrative costs of developing an RFP process in an effort to develop the retail market. I do not think it is necessary or appropriate in this instance to competitively bid out the

[3] Stipulation on day-ahead pricing revisions, DSP IV, May 7, 2007, signed by Duquesne Light Company, Duquesne Industrial Intervenors, Reliant Energy, Inc., Dominion Retail, Inc., Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc., Direct Energy Services, LLC, Strategic Energy, LLC, the Retail Energy Supply Association, and the Pennsylvania Large Energy Users Coalition.

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spot market service for Large C&I customers given the current situation in Duquesne Light's service area.

III. <u>PennFuture's Recommendation to Procure AECs through Ten and Twenty Year Supply Contracts Should Be Rejected</u>

Q. PennFuture witness Speerschneider argues that due to AEC Tier I (non-solar) price forecasts and the relatively more stable load profile of the EDC, it is prudent for Duquesne Light to enter into long-term contracts on behalf of its default service customers for a portion of the Duquesne Light's Tier I obligations.[4] What is your response?

A. It would not be prudent for Duquesne Light to inject long-term fixed default service supply commitments in the Company's DSP VII supply mix at this time. PennFuture's recommendation is based on speculation about AEC market prices, a presupposed level of stability with regard to future default service load levels, and the assumption that the current default service structure will extend far into the future. Furthermore, PennFuture's recommendation would undermine one of the principal goals of deregulation of the generation market, namely to make investors in generation responsible for the success or failure of their investment decisions, not utility ratepayers.

Q. Do you believe that Duquesne Light, as the default service provider, should try to "time" or "beat" the market for AECs or any other supply components?

[4] PennFuture Statement No. 1, Surrebuttal Testimony, p. 3.

A. No. I do not believe that Duquesne Light's default service supply approach should include activities that rely on trying to "time" or "beat" the market for energy, AECs or other supply components, regardless of any AEC price forecast that PennFuture offers. Predicting future electricity and AEC market prices ten and twenty years into the future is inherently uncertain and speculative, and such an approach would put customers' money at risk because the costs of the approach would be passed through to customers. Mr. Speerschneider argues that, "The price projection data PennFuture provided suggests future AEC Tier I Non-Solar prices are likely to rise, allowing the company to enter into lower priced AECs via long-term contracts and enabling the company to sell excess credits (if needed) when prices rise, avoiding financial losses."[5] He further explains that evidence presented by PennFuture shows that future AEC prices are set to increase because of a forecasted undersupply situation where demand for credits outstrips new credit supply.[6] This is mere speculation.

Mr. Speerschneider's analysis fails the "too good to be true" test. First of all, even if PennFuture's claim about future AEC prices was viewed to be correct by other market participants, then it would be reasonable to assume that any prices obtained for long-term contracts to provide AECs would reflect this AEC price expectation. There is no reason to believe that suppliers in any long-term AEC solicitation would bid a price that does not reflect the value that the suppliers believe they could otherwise achieve by selling their AECs in the market in the future.

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[5] PennFuture Statement No. 1, Surrebuttal Testimony, p. 4.

[6] PennFuture Statement No. 1, Surrebuttal Testimony, p. 3.

Second, PennFuture's entire premise is based on the assumption that it is possible to "buy low" on a long-term basis and "sell high" on a short-term basis with very little risks. According to Mr. Speerschneider's analysis, a party could enter into long-term AEC contracts at "low prices" and then sell AEC credits in short-term markets at "high prices" as AEC prices rise over time. He appears to be suggesting that the markets are not working properly and that there is a "financial arbitrage" opportunity in the AEC credit market in which entities could make a lot of money with little risk. I see no evidence of this, and even if this opportunity did exist for a brief period of time, it would quickly evaporate in a properly functioning market as long-term prices should reflect future market price expectations.[7] The premise on which Mr. Speerschneider's testimony relies on is speculative and is inconsistent with economic principles.

Q. Do you think it is reasonable to project Duquesne Light's default service load obligation ten to twenty years into the future?

A. No, and I certainly would not characterize Duquesne Light's default service load as stable or certain over a ten or twenty-year period. There is currently significant uncertainty about the amount of load that Duquesne Light will supply in the future as the Default Service Provider, which is driven by the substantial development of the competitive retail market in Duquesne Light's service area, the retail market enhancements that are included in Duquesne Light's Plan, and future Commission decisions regarding default service policy. This uncertainty is especially large when considered over a ten or twenty-year time

[7] Note that even if Mr. Speerschneider's premise were correct, which I do not believe it is, financial participants in the market without any default service load could "buy long" and "sell short" in large volumes for financial profit. This trading activity would quickly eliminate the opportunity on which his testimony depends.

horizon, which corresponds to the durations of the customer-backed contract guarantees that Mr. Speerschneider proposes be provided to winning bidders. The longer the term of a fixed-price supply product that does not match supply quantities with customer loads, the more likely it is that loads will deviate substantially from expectations at the time that the product was procured, resulting in costly scenarios for customers, such as those in which excess supply must be sold at a loss, or those in which the product price is ultimately above market levels and the product constitutes an unexpectedly high portion of the default service supply portfolio. As a result, PennFuture's suggestion that AEC quantities for the ten and twenty year strips could be procured for a portion of Duquesne Light's AEPS obligation "based on a conservative estimate of Duquesne's load for those years to avoid over-procurement as a potential result of load shifting"[8] is risky.

Q. PennFuture argues that wholesale suppliers are exposed to even greater risk of load uncertainty as compared to Duquesne Light's relatively lower risk of default load migration.[9] Do you agree?

A. I am not sure what Mr. Speerschneider is talking about. He suggests that because EDCs have a relatively stable load profile and relatively low risk of default service load migration, it makes sense for EDCs to enter into long-term contracts. To be clear, Duquesne Light itself really does not assume any load migration risk because these risks are borne by third party wholesale full requirements suppliers. Similarly, Duquesne Light relies on wholesale full requirements suppliers to provide the supply for its default service

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[8] PennFuture Statement No. 1, Direct Testimony, p.19.

[9] PennFuture Statement No. 1, Surrebuttal Testimony, p. 3.

customers.[10] In effect, Duquesne Light largely has exited the generation supply business. It appears that PennFuture would like Duquesne Light to take a more active role in managing supply, at least with respect to AECs. Given that the Company decided to exit the generation supply business, I do not believe that Duquesne Light is well-quipped to make the types of supply decisions that PennFuture envisions.

Q. What is your reaction to the statement that long term contracts for AECs benefit the consumer by creating a hedge against AEC price volatility?

A. While I value the benefits of price stability in default service rates, entering into long-term AEC contracts is not a means to accomplish that objective. AEC costs represent only a small portion of total supply costs, which largely consist of energy and capacity costs. Furthermore, unlike under full requirements contracts, the AEC quantities procured under PennFuture's recommended long-term AEC contracts would not vary with the changing quantities of the default service load obligation, thereby increasing the chance of being stuck with a disproportionate quantity of above-market AECs under contract. In sum, PennFuture's recommendation would do very little, if anything, on its own to mitigate overall rate volatility.

Q. What is your response to PennFuture's argument that long term contracts also reduce risk for renewable energy project developers, enabling these developers to access lower financing costs/accept lower returns on investment?

[10] The only exception is the HPS product discussed earlier in my rejoinder testimony, where the supply is obtained directly from the wholesale competitive market.

A. In general, I believe one of the principal goals of deregulation of the generation market is to make investors in generation responsible for the success or failure of their generation investment decisions, not utility ratepayers. I do not believe that EDC customers located in competitive markets should be responsible for assuming the risks of financing new long-term generation investments. Investments in long-lived generation assets or utility contracts are inherently risky. We can "centrally plan" these decisions, and impose the risks on retail customers, but we should not be surprised when things turn out badly.

One of the most significant areas of potential savings from restructuring is more efficient long-term investments (sometimes referred to as "dynamic efficiency"). Competitive markets can provide significant improvements in resource planning and capital additions. Price signals, rather than administrative determinations, guide economic retirements and capacity improvements, economic new entry, and environmental compliance strategies. Competitive market price signals will encourage the right amount of generating capacity with the appropriate levels of reliability, as well as the right mix of generating technologies in the right locations. Competition makes investors, rather than consumers, responsible for investment decisions with no assured recovery of the investment.[11] All of this works to the benefit of customers.

Mr. Speerschneider attempts to justify his proposal for Duquesne Light to engage in long-term AEC contracts on the basis that it will reduce the risks that renewable energy developers and their investors otherwise would bear, but he ignores the fact that under his proposal risks would be shifted to Duquesne Light's customers for them to bear instead.

[11] If investors in renewable energy projects believe the rising AEC price forecasts put forth by PennFuture, they should not need the guaranteed ratepayer payments included in a long-term contract.

Q. But what about the desire and public policy goal of promoting new renewable generation resources?

A. To the extent that regular market incentives are insufficient to encourage the development of new renewable generation resources, Alternative Energy Portfolio Standards ("AEPS") are intended to promote the development of renewable generation resources. AEPS obligations will determine how much new renewable generation resources are needed. Once these public policy goals are established, competitive market forces should be relied on to meet those standards.

Q. How do you respond to PennFuture's claim that Duquesne Light is in part basing its opposition to long term contracts for AECs on conjecture and theories about the actions of the legislature and the details of legislation that the legislature may or may not consider?[12]

A. It is my understanding that under the current statute, an alternative supplier (other than Duquesne Light) may be approved by the Commission to provide generation service to retail electric customers.[13] I am also generally aware that the Commission has within the past several years considered whether or not EDCs should remain in the role of providing default service. I am familiar with specific proposals in Pennsylvania related to large-scale aggregation programs and retail auctions which potentially could dramatically

[12] PennFuture Statement No. 1, Surrebuttal Testimony, p. 2.

[13] Act 129, § 2803, Definition of Default Service Provider.

impact the nature of default service. Given these facts, in general, I do not think it is wise to engage in contracts that rely on speculation about what future default service regulations will look like ten to twenty years into the future. I do not believe that it is prudent to make an assumption that default service regulations will remain unchanged for the next ten to twenty years, enter into long-term fixed-quantity, fixed-price commitments, and hope that these long-term commitments could "fit" or adapt easily to a new default service framework.

Q. Mr. Fisher, has the Commission expressed its views about EDCs entering into long-term supply contracts at this time?

A. The Commission has pushed EDCs to move toward shorter-term, more market responsive supply contracts. Per the Commission's guidance in the Default Service End-State Order, the Company has made a conscious effort not to include the use of longer-term contracts than those supply products already in place in DSP VI. As a result, I do not believe that it would be advisable to inject long-term default service supply commitments in the Company's DSP VII supply mix at this time.

IV. RESA's Proposal to Shorten the Term Lengths of Default Service Supply Products and to Inject "Hard Stops" in the Supply Procurement Process for Residential and Small C&I Customers Should Be Rejected

Q. Does Mr. Hudson agree in his surrebuttal testimony that 12-month and 24-month procurement contracts proposed by Duquesne Light and OCA, respectively, can be

"market based" at the time that those respective contracts are bid upon by wholesale suppliers?

A. Yes.[14] I think we can all agree that the products are market-based and accurately reflect market prices at the time those prices are established.

Q. Does Mr. Hudson agree in his surrebuttal testimony that wholesale electricity markets exhibit price volatility?

A. Yes. Mr. Hudson does "not dispute the fact that wholesale electricity markets exhibit price volatility."[15]

Q. What then is a critical issue to be decided in this case?

A. A key question for policymakers is: Who should we rely upon at this time to manage the price volatility risks associated with wholesale electricity markets for Residential and Small C&I default service customers over the next two years? Three possible candidates include:

- **Competitive market wholesale default service suppliers** – who supply fixed-price, full requirements default service contracts that provide price stability to all default service customers, who for whatever reason, do not choose an EGS;

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[14] RESA Statement No. 1, Surrebuttal Testimony, p. 3.

[15] RESA Statement No. 1, Surrebuttal Testimony, p. 8.

- **Competitive market retail EGSs** – who may offer fixed-price contracts and could potentially attract default service customers to EGS service; or

- **Residential and Small C&I retail default service customers** – who could be exposed to short-term market price signals and either live with the consequences or seek alternative services with EGSs who may offer fixed-price contracts.

Mr. Hudson states in his surrebuttal testimony that the default service provider (i.e., Duquesne Light and wholesale default service suppliers) should not offer a stable product, arguing that, "I do not agree that the default service provider should be charged with creating that product."[16] It is clear from his testimony that Mr. Hudson ultimately wants EGSs to provide customers with rate stability and views default service as a "backstop" that needs to "continuously reflect market conditions" in order to foster sustainable and robust retail competition.[17] In other words, he believes that Residential and Small C&I default service customers should be exposed to short-term market price signals and retail customers should be forced to deal with the consequences of the fact that wholesale electricity markets exhibit price volatility (which he does not dispute exists). In this case, in order for a Residential and Small C&I default service customer to avoid this market price volatility, *at least* three things need to happen. First, EGSs need to offer "real" fixed prices to customers at reasonable levels. Second, Residential and Small C&I default service customers need to have the information, incentive, and inclination to act on

[16] RESA Statement No. 1, Surrebuttal Testimony, pp. 4-5.

[17] RESA Statement No. 1, Surrebuttal Testimony, p. 4.

those offers, and third, EGSs need to stay in business in order to “make good” and deliver on their fixed price offers.

While I agree with RESA that short-term market price default service is appropriate at this time for Large C&I customers, I do not agree that default service based on a large portion of short-term supply products (such as 3- and 6-month contracts) is appropriate for Residential and Small C&I customers during DSP VII. For all the reasons described in my rebuttal and surrebuttal testimony, which I will not repeat here, this would be bad public policy and would expose default service customers to unnecessary rate instability and risks.[18] During the DSP VII period, I believe that competitive market wholesale default service suppliers should be relied upon to manage the price volatility risks associated with wholesale electricity markets for all Residential and Small C&I default service customers, who for whatever reason, do not choose an EGS over the next two years.

Q. RESA attempts to equate stable prices with “high” default service prices.[19] Do you have any comment?

A. This is not fair and is not necessarily true. First, Mr. Hudson admits that longer term supply products that provide stable prices can be “market based” at the time that those respective contracts are bid upon by wholesale suppliers. Second, it should be obvious that spot market prices are volatile and can change up or down after a longer term supply product is procured. So stable default service rates could later turn out to be “low” or

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[18] Duquesne Light Statement No. 3-SR, pp. 2-26; Duquesne Light Statement No. 3-R, pp. 3-30.

[19] RESA Statement No. 1, Surrebuttal Testimony, p. 5.

"high" relative to contemporaneous spot market prices. Therefore, it is incorrect to equate stable rates with "high" default service prices.

Q. Has Mr. Hudson changed his position regarding the potential impact of stable default service rates on retail competition?

A. Yes. In his direct testimony, Mr. Hudson stated that if the products in the default service supply portfolios are not shortened as he suggests, then market prices may diverge from default service rates for longer periods of time, and the potential for such divergences would discourage EGS participation in the market, leaving customers with "few or no competitive options" <u>even in situations in which default service supply rates are high compared to contemporaneous market prices</u>.[20] He used this logic to argue against stable default service rates claiming that the mere threat of contemporaneous market prices diverging from default service rates for long periods of time was sufficient to keep EGSs out of the market. Now in surrebuttal, he admits, "I do not dispute the fact that, at times, competition can develop in situations where the default service price to compare is fixed for longer periods of time."[21] Mr. Hudson concedes that retail competition can indeed develop with stable default service rates.

Q. How do you respond to RESA's suggestion that a Polar Vortex like that experienced this winter would not expose customers to much price volatility since RESA is not

[20] RESA Statement No. 1, Direct Testimony, pp. 9-10.

[21] RESA Statement No. 1, Surrebuttal Testimony, p. 5.

recommending spot market pricing for Residential or Small C&I customers, nor is RESA recommending 100 percent 3-month, full requirements contracts for these customers?[22]

A. RESA's assertion and reference to Maryland prices is unconvincing. RESA did not conduct an analysis demonstrating the effects on price stability of either Duquesne Light's or RESA's procurement plan. In contrast, I presented the results of an analysis of historical market price movements that indicates that the degree of rate instability for Residential and Small C&I default service customers in Duquesne Light's service area would double if the type of supply portfolio to which Mr. Hudson recommends transitioning were approved.[23]

Q. Do you agree with Mr. Hudson that the Polar Vortex is actually a good reason to use more market responsive contracts?[24]

A. No. I think the POLR Vortex is actually a good reason not to adopt RESA's proposal to inject "hard stops" of supply within the DSP VII period as well as at the end of the DSP VII period. The Company's DSP VII Plan relies on laddered purchases and avoids purchasing 100% of the supply at one point in time or within a short, few-month period of time.

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[22] RESA Statement No. 1, Surrebuttal Testimony, pp. 8-9.

[23] Duquesne Light Statement No. 3-SR, pp. 12-15; Duquesne Light Statement No. 3-R, pp. 13-14.

[24] RESA Statement No. 1, Surrebuttal Testimony, p. 10.

Q. Does Mr. Hudson consider the impact the Polar Vortex would have had on Medium C&I default service customers if those customers would have been on Hourly Price Service as RESA recommends?[25]

A. No. Mr. Hudson is silent on this issue. He neglects to consider the price level and volatility implications of RESA's recommendation if Hourly Price Service were required for Medium C&I default service customers.

V. <u>The OCA's Proposal to Include Spot Pricing in the Residential Default Service Supply Products Should Be Rejected</u>

Q. In his surrebuttal testimony, OCA witness Estomin continues to recommend the inclusion of 5% spot market energy in the Residential default service supply products on the grounds that increased diversity of supply has the benefit of reducing risk even if an element of the more diverse supply is characterized by a more variable price.[26] What is your response?

A. Dr. Estomin and I appear to have a very different notion of market price risks in this instance. When I address reduction of market price risks, I am primarily concerned with avoiding sudden changes in market-based default service rates (i.e., providing customers the benefits of price stability). It should be obvious that adding spot priced energy into the supply portfolio does not reduce the risks associated with market price volatility. Dr.

[25] RESA Statement No. 1, Surrebuttal Testimony, p. 12.

[26] OCA Statement No. 1, Surrebuttal Testimony, p. 8. Under Dr. Estomin's proposal, the full requirements products would be structured such that 95% of the electricity provided would be supplied at the bid price, and the remaining 5% would reflect hourly spot market pricing. OCA Statement No. 1, Direct Testimony, pp. 3, 11-14.

Estomin claims that increased diversity of supply has the benefit of reducing risk. This is incorrect. Adding a volatile product to a stable product does not reduce the risks associated with price volatility. His argument is similar to saying that instead of insuring your entire home, it would be less risky to only insure a portion of it. Perhaps, in some years it may be cheaper to insure only a portion of your home, but it is certainly more risky and could result in disastrous outcomes.

In a procurement approach involving Fixed Price Full Requirements ("FPFR") product solicitations, bidders compete on the basis of the lowest price to satisfy all aspects of the default service customers' load requirements at a fixed $/MWH price, regardless of how the load varies, and regardless of future market conditions or generation costs. As I discussed in my direct testimony, it is reasonable to assume that bidders in the proposed full requirements solicitations will consider the costs and risks associated with all forms of supply (including the diversity of supply options available to them), and will reflect in their bid prices the benefits of any opportunity that they believe is the least-cost supply opportunity, including spot market purchases.[27] One of the benefits of the FPFR products that Duquesne Light has proposed is that the suppliers of these products assume, manage, and cover the complicated supply costs and risks associated with the load requirements, while guaranteeing a fixed price for customers, rather than exposing customers to these risks. By injecting 5% spot pricing into the FPFR products, Dr. Estomin's proposal would reduce the inherent risk-mitigation benefits to customers of the FPFR products.

[27] Duquesne Light Statement No. 3, Direct Testimony, p. 16.

Q. Do you believe Dr. Estomin is concerned with providing Residential customers with the benefits of price stability?

A. Yes, I do. I think he and I would agree that, all else equal, adding spot market energy into the Residential supply mix would likely increase rate volatility for Residential default service customers. It is important to note that Dr. Estomin's portfolio recommendation to include a 5% portion of spot energy is linked to his other portfolio recommendation to include 50% two-year default service supply products, arguing that the inclusion of a significant percentage of 24-month fixed-price full requirements contracts in lieu of 100% reliance on 12-month contracts more than compensates for the increase in price variability that would result from the inclusion of a 5% spot price element.[28]

Q. When addressing your comments about the Polar Vortex, Dr. Estomin states that it is only correct from a historical perspective that residential Default Service customers would be exposed to potentially significantly higher prices with the inclusion of a spot pricing component.[29] Do you have any comment?

A. I am quite happy to be correct from a historical perspective. Despite Dr. Estomin's claim, the fact is that wholesale electricity markets are inherently uncertain. It is difficult to predict the future. Some other unknown event may occur in the future that is unanticipated and may dramatically increase market prices. Protection from unanticipated adverse market events is the benefit of fixed-price, full requirements service. As such, I very well could be correct again as the future unfolds.

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[28] OCA Statement No. 1, Direct Testimony, p.12.

[29] OCA Statement No. 1, Surrebuttal Testimony, p. 8.

Q. How do you respond to Dr. Estomin's claim that including a spot market pricing component would help insulate wholesale suppliers and therefore possibly accommodate lower-priced bids on the full requirements contracts?[30]

A. First of all, I believe wholesale default service suppliers generally are in a much better position to assume market price risks than Residential default service customers. Second, I am not convinced that Dr. Estomin's recommendation would result in lower-priced bids on the full requirements contracts. For example, from a default service supplier's perspective, there is little difference in terms of dollars per MWH between serving an estimated 100 MW (100%) on a full requirements basis and an estimated 95 MW (95%) on a full requirements basis. In both instances, the full requirements portion is essentially the same product, but just scaled down to a smaller quantity.

Q. Please summarize your conclusion regarding the OCA's proposal to include spot market priced supply in the Residential supply portfolio.

A. The OCA's proposal to include spot market priced supply in the Residential supply mix should be rejected for the reasons stated above and included in my rebuttal testimony.[31]

VI. Conclusion

Q. Does this conclude your rejoinder testimony?

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[30] OCA Statement No. 1, Surrebuttal Testimony, p. 8.

[31] Duquesne Light Statement No. 3-R, Rebuttal Testimony, pp. 31-37.

A. Yes, at this time.

Exhibit NSF-5

Responses of the Retail Energy Supply Association
To Interrogatories of Duquesne Industrial Intervenors
Set 1

Submitted by: *Richard J. Hudson, Jr.*
Pennsylvania State Chairman for the Retail Energy Supply Association
Director of Regulatory and Legislative Affairs for ConEdison Solutions

3. Reference Hudson's Direct Testimony at 19, lines 14-15. Please identify whether RESA's proposal to competitively bid out default service would result in changes to any provision within Duquesne's Rider No. 9. If any changes to this Rider are proposed, please identify each change.

RESA RESPONSE:

RESA recommends replicating the existing pricing and cost collection structure with the only difference being that Duquesne would competitively bid out the hourly priced service. Duquesne would be in the best position to determine what, if any, changes are needed to the language in Rider No. 9 to effectuate this change.

Exhibit NSF-6

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE (C)

(Applicable to Rates GL, GLH, L and HVPS and Generating Station Service)

Day-ahead hourly price service provides large commercial and industrial customers with the ability to purchase their electric supply requirements on a day-ahead hourly basis. Beginning January 1, 2008, the Company will supply electricity under this rider by obtaining the requirements through the PJM market and passing through all such costs to the customer to provide this service. This rider is also available for the supply of electricity to generating stations that are not otherwise self-supplying and where the generating station is not otherwise receiving service from an EGS. Metering equipment must be installed at the generating station at the expense of the customer. (C)

MONTHLY CHARGES (C)

Energy charges are hourly and provided at the day-ahead and real-time PJM locational marginal prices based on the customer's day-ahead scheduled load and the customer's real time metered hourly load, plus energy-related ancillary services including PJM administrative charges, adjusted for losses, plus a retail margin. PJM posts the day-ahead locational marginal price on their web site at 4:00 PM EPT. Balancing operating reserve charges will be assigned to each customer based on their pro-rata share of the net system deviation from the day-ahead forecast. Capacity charges are equal to the full PJM Reliability Pricing Model ("RPM") capacity price for the Duquesne Zone, and shall recover the charges associated with the customer's share of the Company's capacity obligation assigned by PJM, plus the charges for capacity based ancillary services. Energy and capacity charges will be calculated using the following formula and adjusted for the Pennsylvania Gross Receipts Tax (GRT) in effect.

$$\sum_{t=\text{Start Hour}}^{\text{End Hour}} [L_{DAt} * (1+ADJ_t) * (LMP_{DAt} + OR_{DAt})] +$$

$$\sum_{t=\text{Start Hour}}^{\text{End Hour}} [((L_{RTt} - L_{DAt}) * (1+ADJ_t)) * LMP_{RTt}] +$$

$$\sum_{t=\text{Start Hour}}^{\text{End Hour}} [|((L_{RTt} - L_{DAt}) * (1+ADJ_t))| * OR_{RTt}] +$$

$$\sum_{t=\text{Start Hour}}^{\text{End Hour}} [(L_{RTt} * (1 + ADJ_t)) * (SR_{RTt} + REG_{RTt} + SCN_{RTt} + \text{REN} + S1A) + L_{RTt} * (PJM_S + FRA)] +$$

$$\sum_{D=\text{Start Day}}^{\text{End Day}} [(CO_D * CChg_D) + NPLC_D * (R_D + B_D)]$$

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued) (C)

(Applicable to Rates GL, GLH, L and HVPS and Generating Station Service)

MONTHLY CHARGES – (Continued)

Where:

t = Particular clock hour in the Billing Period from start hour to end hour for energy charges.

D = Particular day in the Billing Period from start day to end day for capacity charges.

Customer Load

L_{DA} = Day-Ahead scheduled hourly load of the customer, measured in MW. (C)

L_{RTt} = Actual (Real-Time) metered load of the customer, measured in MW. (C)

ADJ_t = Adjustments to the customer load at the retail meter using the same methodology used to determine the hourly load obligations of a customer served by an EGS pursuant to Duquesne's Supplier Coordination Tariff. The hourly load adjustments shall be the sum of the percentage distribution and transmission (if applicable) losses of the applicable schedule as specified in Duquesne's Supplier Coordination Tariff. The Company will also adjust the customer load for the loss de-ration factor defined by PJM. (C)

Energy Charges

LMP_{DA} = Day-Ahead hourly locational marginal price (LMP) in $/MWH including energy, congestion and marginal losses for the Duquesne Zone or Duquesne Residual Zone as applicable. (C)

LMP_{RTt} = Real-time hourly locational marginal price (LMP) in $/MWH including energy, congestion and marginal losses for the Duquesne Zone or Duquesne Residual Zone as applicable. (C)

PJM Ancillary Service Charges and Other PJM Charges

SR_{RTt}= Hourly real-time synchronous reserve charge in $/MWH as calculated by PJM for supporting the customer's load. (C)

OR_{DAt}= Hourly Day-Ahead operating reserve (supplemental) charge in $/MWh as calculated by PJM for supporting the customer's load. (C)

OR_{RTt} = Hourly real-time operating reserve (supplemental) charge in $/MWH as calculated by PJM for supporting the customer's load. (C)

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued)

(Applicable to Rates GL, GLH, L and HVPS and Generating Station Service)

MONTHLY CHARGES – (Continued)

PJM Ancillary Service Charges and Other PJM Charges – (Continued)

REG_{RTt} = Hourly real-time regulation charge in \$/MWH as calculated by PJM for supporting the customer's load.

SCN_{RTt} = Real-time Synchronous Condensing Charge in \$/MWH for supporting the customer's load if this charge is billed separately by PJM to the Company.

S1A = PJM Schedule 1A rate in \$/MWH applicable to the Duquesne Zone.

PJM_S= PJM Surcharge is a pass-through of the charges incurred by the Company for grid management and administrative costs associated with membership and operation in PJM. These are the charges incurred by the Company under PJM Schedules 9 and 10 to provide hourly price service.

R_D = Reactive supply service charge in \$/MW-day to serve the customer's load as calculated under the PJM Tariff Schedule 2.

B_D = Blackstart service charge in \$/MW-day to serve the customer's load as calculated under the PJM Tariff Schedule 6A.

Retail Margin

FRA = The Company's fixed retail adder of \$4.49 per MWH. (D)

Renewable Energy

REN= Pass-through of the costs in \$/MWH for the Company to comply with the Pennsylvania Alternative Energy Portfolio Standards (AEPS) Act of 2004 (Act 213).

Customer's Capacity Obligation and Network Service Peak Load

CO_D = Capacity Obligation in MW for each day associated with supporting the customer's load as described in the section "Determination of Capacity Obligation".

(D) – Indicates Decrease

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued) (C)

(Applicable to Rates GL, GLH, L and HVPS and Generating Station Service)

MONTHLY CHARGES – (Continued)

Customer's Capacity Obligation and Network Service Peak Load – (Continued)

$NPLC_D$ = The customer's daily network service coincident peak load contribution in MW. This quantity is determined based on the customer's load coincident with the annual peak of the Duquesne Zone (single coincident peak) as defined in the PJM Tariff Section 34.1.

Capacity Charges

$CChg_D$= The demand charge in $/MW-day, which is equal to the full PJM RPM Final Zonal Capacity Price for the Duquesne Zone. (C)

PJM bills these charges to the Company as a function of the load measured in megawatts (MW) and expresses these charges as $/MW, $/MWH and $/MW-day. The Company measures the customer's load and energy usage in kilowatts (kW) and will convert the above charges to $/kW, $/kWh and $/kW-day for the purposes of computing the customer's monthly bill.

LOCATIONAL MARGINAL PRICE

The "Duquesne Zone" is the PJM-defined area encompassing the franchised service territory of the Duquesne Light Company. The pricing for the Duquesne Zone contains every transmission load bus on the Company's system. PJM will determine the locational marginal price for the Duquesne Zone and an hourly nodal locational marginal price for each load bus. Load Serving Entities (LSE's) and wholesale transmission customers have the option of electing energy settlement at the hourly nodal prices.

The "Duquesne Residual Zone" is the pricing zone determined by PJM in the event that LSE's or other wholesale transmission customers in the Duquesne Zone elect settlement based on nodal locational marginal energy prices. In such event the Duquesne Zone locational marginal price will be replaced by the Duquesne Residual Zone locational marginal price and:

(C) – Indicates Change

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued) (C)

(Applicable to Rates GL, GLH, L and HVPS and Generating Station Service)

LOCATIONAL MARGINAL PRICE – (Continued)

(i) the pricing for such zone will be calculated by PJM using a load-weighted average of the nodal locational marginal prices of all load buses within the Duquesne Zone, but excluding from such calculation the weighting at the respective nodal prices of the load served by LSE's or other wholesale transmission customers who have elected nodal settlement; and

(ii) settlement for all LSE's and wholesale transmission customers in the Duquesne Zone that have not elected nodal settlement, will have their load obligations settled on an hourly day-ahead, hourly real-time or other periodic basis at the respective PJM-determined price for the Duquesne Residual Zone for such period.

DETERMINATION OF CAPACITY OBLIGATION

The capacity obligation subject to the Demand Charges in this rider will be the customer's share of the Company's capacity obligation determined by PJM. The Company's capacity obligation will be calculated by PJM based on the Company's peak system load and will be the basis for the capacity obligation for the following planning year. (C)

In determining the customer's share of the capacity obligation, the Company will calculate the customer's peak load contribution. The peak load contribution is based on the customer's load coincident with the peak hour of the five peak days as determined by PJM. The customer load in each of these five hours, adjusted for the Company's transmission and distribution line losses and the customer's share of unaccounted for energy will be averaged to calculate the customer's peak load contribution. Customers may participate as a Demand Resource or as an Interruptible Load Resource ("ILR") under RPM in PJM. Any and all charges or credits associated with the customer's participation as an ILR will be applied to the customer's bill. (C)

NOTIFICATION AND ELECTION OF SERVICE

Customers may elect to purchase their supply requirements through this rider at any time according to the requirements of Rule No. 45. Customers that do not elect service with an EGS will default to hourly price service under this rider. (C)

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued) (C)

(Applicable to Rates GL, GLH, L and HVPS and Generating Station Service)

DAY-AHEAD SCHEDULING GUIDELINES (C)

The Company will provide an hourly load forecast (with losses) on the DLC customer choice web site for each customer taking service under this rider by 8:00 AM EPT each PJM business day. The customer may update the Company forecast prior to 10:00 AM EPT. The forecast at 10:00 AM EPT will be considered the final forecast values in the day-ahead demand bid and will be binding upon the customer. The Company will aggregate all of the final customer forecasts, de-rate per the mean PJM EDC loss de-ration factor, and submit this aggregated day ahead demand bid prior to 12 PM EPT PJM business day-ahead. The Company will review the forecasted loads provided by the customer to ensure they are reasonable so as to not affect charges that may be allocated to other participating customers.

All load submitted as part of the day-ahead demand bid for each customer will be billed to the customer at the day-ahead LMP. PJM will calculate the balancing charges based on the difference between the day-ahead demand bid and actual load. The customer will receive a charge or credit at the real-time LMP if the actual load is greater than or less than the demand bid, respectively. PJM balancing operating reserve charges will be assigned to each customer on this rider based on their pro rata share of the net system deviation from their portion of the day-ahead demand bid.

The Company will apply the procedures for load forecasting, day-after load estimates and supply schedules, and reconciliation as defined in the Company's Electric Generation Supplier Coordination, Rules 6, 7 and 8, respectively.

GENERAL

The Supply Charges are intended to recover the market costs of providing Default Service to customers in PJM as these costs may change or be redefined from time to time. The Supply Charges shall be calculated using the formula and prices referenced above, but may be revised from time to time, as necessary, to reflect changes in PJM rules and charges. The Company is required to include renewable energy sources as a component of providing POLR service. The Company will pass-through the charges required to comply with the Alternative Energy Portfolio Standards (AEPS) as those compliance requirements change. The formula is illustrative to reflect the charges in the PJM tariff and is subject to change at any time, as PJM rules, charges or market parameters change. (C)