STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC CO. d/b/a NATIONAL GRID'S PROPOSED STANDARD RATES PURSUANT TO 2018 STANDARD OFFER SERVICE PROCUREMENT PLAN – DOCKET NO. 4692

Comments of Direct Energy Business, LLC and Direct Energy Services, LLC in Response to the Division of Public Utilities and Carriers Rate Mitigation Proposal

Direct Energy Business, LLC and Direct Energy Services, LLC ("Direct Energy") hereby respectfully offers the Rhode Island Public Utilities Commission (the "Commission") the following Comments in connection with the July 18, 2018 Standard Offer Service rate filing by National Grid ("National Grid" or the "Company").[1]

I. Introduction

The Direct Energy family of companies has approximately 6,000 employees, and approximately 6 million customer relationships in North America. As a national retail supplier of electricity, natural gas and energy services, Direct Energy serves the residential, small commercial and industrial market segments. Direct Energy currently serves a substantial number of Rhode Island electricity and natural gas customers in the National Grid service territory. In addition, Direct Energy also operates as an active wholesale supplier of electricity products to many of New England's electric utilities, including National Grid here in Rhode Island. Indeed, Direct Energy most recently provided National Grid wholesale Standard Offer Service ("SOS") from October 1, 2017 through March 31, 2018.

The Commission is at an important crossroads on its journey to develop a fully competitive energy market and to reap the economic and environmental benefits that will come with that success. There are not one, but two, significant decisions looming before the Commission. The first is the decision that will be made in the instant proceeding – to mitigate

[1] By separate filing on this date Direct Energy has moved the Commission to intervene in this proceeding.

market prices or not. The second occurs after this proceeding, deciding on a path to reach the desired end state. The first decision may have significant impact on the second.

On March 1, 2017, National Grid filed its SOS procurement plan for 2018. Its procurement plan remained unchanged from the 2016 procurement plan that was approved by the Commission. The 2016 procurement plan employed a laddered and layered repeating procurement schedule for the residential and commercial Groups. This type of procurement was first introduced in the 2011 SOS procurement plan (Docket No. 4149) and according to National Grid, is their "preferred procurement method because the transactions are at different times and are dollar-cost averaged to create a blended supply rate."[2]

In a memorandum dated March 23, 2017, ("March 2017 Memorandum") the Rhode Island Division of Public Utilities and Carriers (the "Division") noted its support for National Grid's procurement plan, stating:

> The Division concurs with the proposal to continue to procure Standard Offer supply in accordance with the approved 2016 Plan, which procures small amounts of supply at various times through various procurements, leaving 10% of the supply obligation to the spot market. We agree that the Plan will meet the Company's goals of mitigating volatility for small customers, minimizing risks of price shock, and sending some seasonal price signals through the newly initiated pricing periods of April-September and October-March."[3] No party objected to, or otherwise filed comments related to, National Grid's procurement plan for the 2018 procurement cycle.

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[2] National Grid's March 1, 2018 letter filing seeking approval of 2016 procurement plan for the 2018 procurement cycle, p. 1, available at http://www.ripuc.org/eventsactions/docket/4692-NGrid-2018-SOS-ProcurementPlan(3-1-17).pdf.

[3] Division Memorandum dated March 23, 2017 filed in this docket.

On May 12, 2017, the Commission issued an order in this docket approving, as filed, National Grid's procurement plan for the 2018 procurement cycle.[4] In approving the procurement plan, the Commission noted that the:

> 2018 SOS Procurement Plan, a continuation of the 2016 Procurement Plan as modified in Order No. 22677, will continue to meet the goals of procurement as set forth in that order. The 2018 SOS Procurement Plan will also allow the PUC to continue to observe and analyze the effect of changes to the procurement and billing periods approved in the 2016 SOS Procurement Plan.[5]

In its July 18, 2018 filing (the "Proposed SOS filing"), National Grid filed its proposed six-month SOS rates that were generated from implementation of the process approved by the Commission and that has been the primary procurement model for Rhode Island for several years. The proposed rates are for the period from October 2018 through March 2019 for the Residential and Commercial Group customer classes and three-month variable rates for Industrial Group rate classes. The rate proposed in the SOS filing would result in an increase in the Standard Offer rates of approximately 43% for residential customers compared to current rates – from 8.486 cents per kWh to 12.129 cents per kWh. The small commercial rates proposed will result in an increase from 8.190 cents per kWh to 11.876 cents per kWh. The change from last year's winter rate for 2017-18 to the utility's proposed residential winter rate for 2018-19 is, however, smaller. That increase is from 9.515 cents per kWh to 12.129 cents per kWh, representing a 26% year over year difference.

The Division reviewed the Proposed SOS filing, including the confidential and public schedules and procurement information supporting the calculation of the rates. In response to

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[4] Report and Order In re: The Narragansett Electric Company d/b/a National Grid's 2018 Standard Offer Service Procurement Plan and 2018 Renewable Energy Standard Procurement Plan, Docket No. 4692, May 12, 2017.

[5] *Id.*, p. 3.

that review, on August 10, 2018, the Division filed a Memorandum that recommended a "rate mitigation proposal" (the "Division Memorandum"). With the rate mitigation proposal, the Division recommended that the Commission act to moderate the impact on customers of the proposed rate increase. The rate mitigation proposal identifies three options that the Division believes are available to the Commission to mitigate the impact of the rate increase to Rhode Island's residential and small commercial rate classes.

Direct Energy does not support the market interventions proposed in the Division Memorandum. Direct Energy believes that if the Commission intervenes at this time, the short-term and long-term market ramifications will be significant. Direct Energy prefers that the Commission not alter the market outcomes, but, if it does, to should do so in a minimalist fashion – one that will have the least impact on market outcomes. Accordingly, Direct Energy is prepared to provide a set of alternative recommendations that it believes will accomplish the same public policy goals the Division is trying to achieve, but with a much lower impact on consumers and the competitive energy market.

II. The Division's Memorandum

The Division's analysis of bill impacts and its options provided to the Commission to protect customers might seem well-intentioned. However, they suffer from at least four significant deficiencies:

1) they do not protect customers;

2) they will result in over-consumption of electricity and drive the associated emissions increases and other market impacts associated with the over-consumption;

3) implementation of the proposals will have a negative long-term impact on the Rhode Island electricity market and its customers; and

4) they will harm the continued development of the competitive energy market which is the policy of the state that the Commission is trying to achieve.

Most importantly, the Division's recommendation that the Commission "act to moderate the impact of regional cost drivers on Rhode Island's ratepayers" is significantly flawed. The Division offers no evidence that a moderation of regional costs is needed or even wanted by Rhode Island ratepayers. The Division pointed out that Rhode Island has the lowest costs of all of the regional utilities and that the "Rhode Island procurement policy has mitigated the rate impact for the past three winter periods, as compared with other New England states…."[6] The Division offers no analysis of the coming winter period against the other regional utilities and offers literally no data to support that customers are seeking or in need of any type of mitigation.

No entity, including Direct Energy, wants to see price spikes concerning 80% of the energy market and the resulting numerous impacts therefrom. Direct Energy has observed price spikes in several different deregulated energy markets, resulting from an array of different market drivers over the past two decades, and has helped regulators address those respective situations. California price spikes were caused by a faulty market design and market gaming (enabled by the bad market design). Maryland price spikes were caused by market design and unfortunate timing related to the expiration of regulated rate caps. Pennsylvania and Delaware had the same experiences as Maryland. New York experienced significant rate shock due to the Polar Vortex which was exacerbated by its market design. Now, Rhode Island is attempting to mitigate a rate increase that is being generated by its approved market design and some recent capacity retirements.[7] The common theme in these collective experiences is an inadequate

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[6] 2018 Division Memorandum, Attachment 1.

[7] According to ISO-New England, more than 4,600 megawatts, an amount equal to about 16% of the region's current generating capacity—will have shut down between 2013 and 2021. The closures of just two of those resources—Brayton Point Station in May 2017 and Pilgrim Nuclear Power Station by May 2019—removes 2,200 MW of non-gas-fired capacity. *See* ISO-New England, ***Retirements of Non-Gas-Fired Power Plants,*** available at https://www.iso-ne.com/about/regional-electricity-outlook/grid-in-transition-opportunities-and-challenges/power-plant-retirements.

market design – typically one where utilities and regulators believe that they can out-manage market dynamics. It is simply not possible.

Rhode Island is unfortunately now a potential victim to the market design that it has espoused over the last several years as one that will protect consumers. Time and time again, the markets have shown that locking consumers into an artificially low-cost, mechanically-hedged, no service standard energy product is not protection at all. Instead, it lures customers into a false and inappropriate sense of comfort and security. When that false utopia is disrupted, the ramifications are felt by the majority of customers in the market because they have taken no action to protect themselves.

A. No Real Protection for Consumers

The Division's recommendations do not "protect" consumers over the long-term. The options simply mask the impact of the rate increase with rate deferrals and reconciliations. Yes, each of the Division's options has the effect of lessening the rate increase customers would otherwise see on their November invoice (caused by the October rate increase). However, over the course of the next year, consumers will not save any money. In fact, when interest charges are applied to the deferrals, the state's residential and small commercial consumers will actually pay more than they otherwise would pay over the course of the year, if the market price is left to govern. Last winter, National Grid sold approximately 1.3 billion kWh to standard offer customers. If that amount holds this winter, the reduction requested by the Division (1.139 cents per kWh) would result in a deferral of $14.8 million, which would accrue interest charges of approximately $500,000 over the subsequent six months, depending on allowed interest rates and actual recovery method.

B. Ignoring Market Signals Has Multiple Short-term Risks

Any type of rate deferral will send the wrong market signal to the customers. New England has transitioned from a summer peaking system to a winter peaking system. As a result, winter price increases are now, unfortunately, a reality throughout the Northeast. This trend began several years ago and because of certain constraints in the energy markets, is likely to occur for at least the next several years. A market signal of a higher winter rate is an appropriate economic signal, and mitigating that rate is not without significant risk. A deflated price signal can lead to consumption levels above ordinary market expectations and thus, can lead to increased emissions. It is important to note that this price signal was delivered to the market through the mechanisms that National Grid, the Division and the Commission all supported and approved and a mechanism that has been contemplated, discussed and tweaked over several years.

The most recognizable harm to ignoring the price signal is that a mitigated price signal will lead to consumption levels above the ordinary market expectation, which has several ramifications discussed in the next section. One immediate impact, however, is that the over-consumption will lead to increased emissions in the winter months. Those emissions may or may not be offset somewhat over the course of the year by consumers using less next summer when the price is artificially high.[8] Regardless, the emissions impact in the winter is real.

ISO-New England ("ISO-NE") has acknowledged that the transition to a winter peaking system has come with "a bill for high energy prices when energy supply is constrained — as well

[8] These comments do not attempt to conduct the analysis of which plants will run and what emissions will be generated as a result of the market price mitigation, but it should be noted, at a minimum, solar resources across the ISO-NE market run much less in the winter months than in the summer for no other reason other than hours of daylight. So, the increased demand from over-consumption in winter will largely not be met by solar resources.

as the potential for greater risks to power system reliability and higher emissions."[9] Over-consumption in Rhode Island in the winter of 2019 could, in an extreme weather event, result in problematic outcomes for the ISO-NE market. The New England winter market constraints are real and should not be ignored without extremely compelling justification, and that justification is lacking as of now.

C. Ignoring Market Signals Has Compounding Long-term Risks

The market mitigation options presented by the Division have potential detrimental long-term impacts on both the customers and the market (which will in turn further impact customers). As a direct customer impact, the over-consumption will lead to the collection of deferral costs that will be larger than the amount of costs collected at full rates. The application of interest to the deferral was discussed above. In addition to the interest charge, the "over-consumption" will lead to a larger base deferral, which will be collected, with incremental interest. These are more easily understood with an example. Assume the expected consumption of electricity at 12 cents per kWh was 1,000 kwh. That customer's invoice would be $120 (ignoring distribution, taxes and other charges). However, with a lower price, that customer would be expected to consume more. For example, at 10 cents per kWh, that customer might consume 1,050 kWh. That customer's invoice will only be $105 – the appearance a $15.00 savings. However, because of the increased consumption, that customer will carry with it a deferral on an extra 50 kWh and the associated interest charges. That customer's total cost for the month will become, after the deferrals are collected, $126 plus associated interest charges – a real increase of $6.00 plus interest. If the approximately 387,000 standard offer residential customers each used just 50

[9] *See* ISO-New England, 2018 Regional Electricity Outlook, p. 4, available at https://iso-ne.com/static-assets/documents/2018/02/2018_reo.pdf.

kWh per month more than expected, that would yield incremental costs associated only with the excess consumption of almost $14 million exclusive of any interest charges.

That over-consumption will have a long-term irreversible impact on the wholesale market as well. Wholesale energy providers participated in an auction process with a certain set of expectations and parameters, including a track record of customer usage data, customer migration data, peak loads and other parameters. As is shown in the paragraph above, a mitigation approach will render these assumptions meaningless. Unfortunately, the wholesale market participants generated bids understanding the impact that their bid price would have on each of these parameters. For example, the wholesale market has expectations about load migration if six-month prices are at a certain level. They also have expectations about load consumption at certain prices. The wholesale providers calculate bid prices and make firm offers in the auction that consider all of these dynamic pieces. Simply ignoring the results from the approved auction process and imposing a Commission-generated price on the market invalidates all of that intelligence and all of the assumptions that are a fundamental part of the bid price, and decoupling the bid price from market dynamics.

The net result of the Commission ignoring or mitigating the price signal will be a hidden "tax" that will be included in every future wholesale auction. It will be a "distrust tax" – a risk premium that risk managers will require in every Rhode Island auction or bid process. Risk managers will forever be wary that if the Commission doesn't like the offer, it is going to change the outcome. It will also have the compounding impact that as prices go higher, the risk premium will have to increase because there will be more risk associated with the offer. Rhode Island consumers will pay this "distrust tax" long into the future.

The Division Memorandum has caused the risk management discussion to begin. In order the stop it, the Commission should rule in an unwavering and steadfast manner that the market has delivered a signal through a process that it has long-endorsed and that price signal must be observed.

D. Manipulating Market Signals and Pricing Harms Markets

The regulatory manipulation of pricing harms the competitive energy market. The Division outlined several risks associated with its proposals in its memorandum. They include a loss of seasonal pricing signals and a negative impact on retail choice.

Rate mitigation, which artificially lowers the cost of electricity during the winter, moves away from fundamental economic principles of cost causation. Manipulating a rate to create one that does not reflect seasonal price signals is inconsistent with the goals of the Commission, especially with the Commission's Docket No. 4600 - Investigation into the Changing Electric Distribution System and Docket No. 4600-A - PUC Guidance Document.[10] Most notably, in *Section III. Rate Design Principles*, the Commission has adopted certain principles to be applied in assessing the reasonableness of rate design. As part of the Commission's deliberation of the Division's proposed SOS rate mitigation plan, Direct Energy encourages the Commission to consider the rate design principles memorialized in Docket 4600 that are particularly pertinent here. Among other attributes, rates should:

- Promote economic efficiency over the short and long term;
- Provide efficient price signals that reflect long-run marginal cost;
- Empower consumers to manage their costs; and
- Constitute a design that is transparent and understandable to all customers.

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[10] Rhode Island Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving the Narragansett Electric Company d/b/a National Grid. Refer to section III. Rate Design Principles found on pages 4-6.

The hybrid wholesale/retail SOS market design present in Rhode Island today already disadvantages competitive retail suppliers on many fronts. If a regulator implements an artificial utility supply rate that is set below short-term energy market costs, not only does it negate the attributes espoused above, it makes it even more difficult for NPPs to compete against the mitigated price. In the wake of the true market signal, the NPP could save consumers money through the competitive market. An artificial reduction in winter energy prices injects an extraordinarily burdensome "benchmark" into the market against which NPPs such as Direct Energy must compete. Moreover, it does not provide the state's electricity consumers with the level of appropriate transparency and necessary price signals to make informed and rational buying decisions. NPPs, including Direct Energy, cannot compete against artificial prices that either have been or will be manipulated by regulators.

Rhode Island currently has a functioning competitive energy market. The state supports Empower RI, a website where customers can shop for an electric supplier at https://www.ri.gov/app/dpuc/empowerri/rate_card. On August 21, that website showed 21 offers for electricity contracts with terms of 12 months or longer and a handful of shorter-term contracts. All but two of the long-term contracts were for prices lower than the expected October rate of 12.129 cents per kWh. For example, there is a 6-month rate available on the website for 8.3 cents per kWh. By acting unilaterally, the Commission will be essentially removing the customer's choice to find what plan works best for them.

Imposition of an artificially low SOS price will also make it difficult for NPPs to explain why their product is better over the course of the year. In a perfect world (in the imperfect mitigation scenario), a customer would see a 12-cent per kWh bill, a 2-cent per kWh credit and a note explaining that the credit is going to be recovered through an energy surcharge the following summer. This will unnecessarily confuse customers and complicate the bill. If the future recovery of the surcharge is on the energy portion of the bill, customers would migrate to NPPs and National Grid would be stuck with an under-collection. So, in the imperfect world, NPPs will have to say that they can't beat the winter price (because the Commission has artificially reduced it) but we can beat your summer price, (because it is artificially high) but if you switch to us, you are going to continue to pay the surcharge to recoup the discount you received over the winter (so the NPP can't really beat the summer price). The confusion to the customers will be immense. That will cause distrust and it will only serve to make those customers more likely to stay with the utility and remain on SOS because of the false belief that the utility is designed to protect consumers.

III. Market Evolution Strategies

Rhode Island is saddled with a retail energy market design that has proven ineffective, especially for residential and small commercial customers. There are several reasons for this, most notably, the SOS product design. Fortunately, a sequence of events is forcing market changes in the near future. In a very short while, Rhode Island will need to implement a new form of basic service for customers who fail to choose an electric supplier. National Grid is also considering significant investments in its infrastructure to improve the market.

Rhode Island is at least tentatively envisioning a fully modernized grid with advanced meter functionality. However, for that grid to provide tangible benefits to consumers as envisioned, the entire market must evolve. The market must be developed around a comprehensive business model that includes dozens, if not hundreds, of energy service companies, including NPPs and companies that offer numerous other services, including energy efficiency, automated energy management, demand response, distributed energy resources and others not yet envisioned. Conversely, the market will not deliver customer benefits if it is designed around the archaic concept of a command and control utility that hopes to be the sole deliverer of end-state products and services. The Commission should not proliferate the model where the utility maintains market dominance.

Direct Energy supports full-scale deployment of a modernized electric grid with automated meter functionality and will continue to participate in the regulatory processes to facilitate full deployment of a smart grid. Direct Energy firmly believes that these tools will provide the platform for companies to deliver significant value to consumers, including lower energy costs, lower energy consumption and reduced power plant emissions. However, that value will be significantly muted if the Commission continues to believe that it and the utilities need to protect and can protect consumers from fluctuating energy prices. For example, a demand response product offers no value to consumers if prices are not allowed to increase. Similarly, consumers don't need advanced metering functionality if a real-time price signal does not accompany it. Stated another way, "smart" meters and "smart" grids are of no value if they are tied to a "dumb" price. The path to achieving a lower emissions future is to allow the market to deliver real time price information to customers and to fully equip customers with the tools needed to manage their electricity consumption in all hours, including peak hours.

The mindset that consumers need to be protected from the market should be abandoned or the investments in smart grid will never deliver their potential value. Regulators don't protect consumers from price increases in other similar markets, for example in gasoline, cell phones, insurance products, homes, or cars. In January of 2018, the American Automobile Association ("AAA") reported that at an average price of $2.49 per gallon, the national gas price average is the most expensive at the start of a new year since 2014.[11] Data from the US Energy Information Agency ("US EIA") shows that gasoline prices rose 68% between February 2016 and May 2018. Gasoline prices rose 40% in one 4-month period in that time frame.[12] Consumers managed around high gas prices with electric vehicles, less driving, better fuel efficiency, car-pooling, mass transportation and other tools. Energy markets can provide similar energy management tools to consumers.

This current price increase essentially proves that markets and market pricing cannot be managed by a highly regulated and managed utility portfolio. Instead of trying to manage the market and have a scenario where 90% of all residential customers are going to experience a 43% rate increase as a result of policies endorsed by National Grid and the Division and adopted by the Commission, the Commission should endeavor to fix the market so that customers have the tools to empower themselves to manage their own electricity procurement. Direct Energy presents below, a list of tools that should be incorporated into the energy markets in Rhode Island so that consumers will in fact see a fully robust and competitive energy market that is offering competitive energy products and services to all customers. Some of these proposals can be implemented in a rather short period of time and potentially be in effect before the winter. Others will take longer to implement but the Commission should start on them now so that when the grid is ready with advanced capabilities, the market will be ready to provide services to maximize the value of those capabilities. By the time that smart grid capabilities have been deployed, the regulatory mindset must be fully replaced by the notion that consumers are empowered to protect themselves with tools available in the market.

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[11] See: https://newsroom.aaa.com/2018/01/2018-kicks-off-expensive-gas-prices-since-2014/.

[12] See: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMM_EPM0U_PTE_NUS_DPG&f=W.

A. Short-term Evolution Strategies

- *Enhance the consumer shopping website.* The Commission's electricity shopping website, which can be found at https://www.ri.gov/app/dpuc/empowerri/rate_card, should be updated to emulate some of the more advanced websites available in the market. Two more robust examples include the websites developed for consumers in Pennsylvania and Massachusetts. Pennsylvania's www.papowerswitch.com, provides more detailed information about companies' specific offers. Additionally, the Pennsylvania website provides direct links to suppliers' websites where customers can easily and rapidly enroll with a supplier and while it shows the default service option, it also shows the volatility of the default service option. The Pennsylvania website has proven to very successful, receiving a commendation from the Governor's Office of Transformation, Innovation, Management and Efficiency ("GO-TIME") for the use of technology to promote increased citizen engagement. According to the Pennsylvania PUC, its shopping websites attract nearly one million visitors per year. The PUC also noted that a survey conducted about the energy market revealed that 90% somewhat or strongly agree that the website provides helpful information; 87% of respondents are very or extremely satisfied with the website; and 70% say that the website is very or extremely easy to navigate.[13] Massachusetts recently deployed its own shopping website, www.energyswitchma.gov. This site offers its viewers the same type of valuable content, but also allows offers to be sorted by price, term length or renewable energy content, whichever attribute the customer deems more important. Additionally, a customer can request that energy-related products and services and/or non-energy-related products and services be shown as well. Inclusion of these type of attributes and capabilities in the website redesign is believed to facilitate more rapid deployment of rooftop solar and/or energy efficiency products. Enhancements to the Empower-RI website could provide an excellent platform to better inform and educate electricity shoppers about opportunities for enhanced energy products and services that would allow for savings and other energy benefits. In addition to simply updating the website, the Commission should actively

[13] See: Pennsylvania Public Utility Commission, Press Release*: PUC Websites for Natural Gas and Electric Shopping Receive GO-TIME Award for Promoting Increased Citizen Engagement,* August 14, 2017.

promote the website and direct National Grid to do the same through bill inserts, bill messages, public service messages and other media.

- *Adopt rapid enrollment features.* The Commission should direct National Grid to develop a platform that will allow a customer to enroll with a NPP using simple customer-identifying information such as name and service address. Today, a customer is required to know their account number to switch to a NPP. The utility account number, which is completely unrelated to anything personal about the customer, should not be required. A picture ID or social security number that links to the service or billing address should be sufficient proof to enroll with an NPP. Immediate access to historic usage information should also be made available for this scenario so that the suppliers can tailor a product based on the customers' needs as shown with the historic usage data. For example, the data might indicate that an efficiency product could be of high value to a customer. This type of enrollment capability will allow the industry to rely on more traditional types of retail customer engagements such as retail stores and kiosks. This model works very well in the cellular industry and has been deployed in the electric and gas industry in more evolved markets.[14]

- *Fully allocate appropriate costs to Standard Offer Service.* The provision of SOS is heavily subsidized by the distribution company. National Grid allocates essentially no costs of operations of its SOS, yet it uses distribution resources to provide billing, collections, customer care, finance and accounting services, regulatory support, executive leadership and other services that support SOS. It is possible to allocate an amount of costs that are required to manage the standard offer business to standard offer customers in such a way that the total cost to customers in aggregate stays constant, yet the supply rates are more reflective of the true cost to provide the supply to standard offer customers. Additionally, a program can be designed to ensure that the distribution company is held harmless and recovers its full distribution revenue requirement. In sworn testimony in ongoing distribution rate proceedings, it has been shown that between 1.0 and 1.2 cents per kWh should be allocated away from distribution rates and into

[14] See: http://www.energychoicematters.com/stories/20170214a.html.

standard offer rates.[15,16] Additionally, a revenue neutrality mechanism designed to ensure that the distribution utility fully collects its revenue requirement was presented in the New Jersey proceeding.[17] The Commission should require National Grid to fully allocate costs to SOS and implement a collection mechanism as is described in a New Jersey proceeding.[18] This change would be reflective of a true and appropriate allocation of costs that has been until now, missing from the market, unjustly benefiting SOS customers and National Grid. While this process might seem illogical in the context of a rate mitigation discussion, because it may show the appearance of an increase in rates, it actually produces a "better" rate for the customer, providing the customer with better vision into its competitive options. It also provides for a decrease in distribution rates, so the net payment from the customer is nearly equivalent. Direct Energy is happy to provide the Commission with more details about how this program can be implemented with no harm to customers.

B. Longer-term Evolution Strategies

- *Data availability.* Utilities have long argued that they are the owners of customer usage data. The ownership of and access to consumers' data will forever be a constraint to a robust competitive energy market as long as the Commission holds the view that the utility owns the data. It is the customers' data. Customers have paid for data collection and the development of and continued operation of data management systems. The data is also unique to each customer. Therefore, customers should have immediate and unfettered access to their own data. Similarly, they should be allowed to grant NPPs and

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15 For support of the 1.0 cent allocation of costs to Standard Offer Service in the PSEG distribution territory in New Jersey, see: The testimony of Frank Lacey *in the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, BPUNJ No. 16 Electric and BPUNJ No. 16 Gas and for Changes in Depreciation Rates, and for Other Appropriate Relief*, BPU Docket Nos. ER 18010029 and GR18010030. ("Lacey NJ Testimony," attached hereto.)

16 For support of the 1.2 cent allocation of costs to Standard Offer Service in the PECO distribution territory in Pennsylvania, See: the testimony of Chris Peterson in *Pennsylvania Public Utility Commission v. PECO Energy Company*, PAPUC Docket No. R-2018-3000164.

17 *See* Lacey NJ Testimony, attached hereto.

18 A Revised Joint Settlement Agreement resolving all outstanding issues in National Grid's request for an increase in distribution rates is currently pending before the Commission. Direct Energy is a signatory to that joint settlement agreement. Nothing in this proposal should in any way alter the revenue requirements approved by the Commission, or any other terms of that settlement agreement. This suggestion would simply re-allocate some of the costs and collect them from different buckets. This reallocation is critical to making the Rhode Island energy markets competitive and beneficial to consumers in the State.

other third-party energy service providers the same type of immediate and unfettered access to the data. It is only with access to real-time or near real-time data that the consumers will benefit from the modernized grid. A consumer derives no benefit from learning today that yesterday's real-time price was $1000 per MWH and that the customer's load was high and manageable. As the Commission defines the role of the utility it should be very prescriptive about the consumers' ownership of their own data and the costs required to access that data (it should be available at no incremental to cost to customers who would like access to it).

- *Supplier Consolidated Billing ("SCB").* SCB is the same concept as Utility Consolidated Billing that has been deployed in Rhode Island and would also include a "reverse purchase of receivables" provision. Under SCB, the NPP would create and deliver the invoice to the consumer instead of the utility delivering the invoice. Under this market construct, suppliers would build out a billing system that would capture their own full array of value-added services and save a line on the bill to pass through the utility distribution costs. This is in contrast to the near impossible task of a utility building out a billing system that can accommodate all of the NPPs' value-added products, services and other offerings. SCB creates a framework where suppliers can functionalize the tools needed for the State to deliver on its environmental and energy-related goals. The utility billing construct is one of the primary constraints to innovative products and services today. In fact, in discussing one alternative to mitigating prices, the Division's Memorandum states "Specifically, the Company does not have its billing system set up to offer a last resort service fixed option. System programming would not only be implicated, but it also would give rise to a considerable number of decisions on implementation and the terms of service. In other words, it was a much more complicated undertaking than one might initially contemplate."[19] The Commission should examine this statement in great depth when determining what it expects from a future energy market. If this constraint is so big that it cannot be implemented before October, one can only imagine the difficulties that will ensue if the utility continues as a billing agent. Utility consolidated billing is akin to a scenario where UPS or FedEx charges its

[19] See: Division Memorandum, p. 5.

customers for the goods it delivered. Of course, that scenario is unfathomable. Instead, we pay the product provider and they include the shipping in their charges to the customer. If the energy market continues to move forward with a singular utility billing platform, that platform will forever be a constraint on the market. The implementation of SCB may present certain technical, regulatory and business issues to address. Regardless, this issue is paramount to the transparent delivery of value-added products and services. The Commission should set this as one of the fundamental end-state market design goals, so that these market products and services can be effectively developed, sold, managed and invoiced. It is specifically the types of products that the Commission is seeking that are being choked out of the market by utility billing limitations.

- *Overhaul Standard Offer Service procurement.* The Commission should undertake an effort to evaluate its goals and strategies for SOS procurement. Is it a protectionist strategy? That strategy appears to have failed in this and multiple other markets over time. It is bound to fail again under a new set of circumstances. Is it a strategy to educate and inform customers about pricing, energy management options and environmental stewardship? A micro-managed procurement process is not going to achieve those goals. Is it truly a last resort service? One in which customers are incentivized to ignore? Many different market designs have been implemented around the country and this Commission can learn a lot based on the experiences from those markets. These models include a "retail auction" model as has been implemented in Maine. The hybrid wholesale/retail model has been implemented in several states and is driving results very similar to what is seen in Rhode Island. That model unfairly advantages the utilities and the majority of customers are not availing themselves of products and services even where advanced grids have been deployed. In the Ohio gas markets, suppliers bid periodically for the right to serve all the gas default service customers. The bid is based on all non-commodity costs and the commodity is passed through at market rates. Finally, for the Texas electricity and Georgia gas markets, the states have adopted a true "last resort service" where customers are all with suppliers and if an event causes a supplier to abruptly leave the market, customers revert to last resort service. Direct Energy is willing to further detail the benefits and disadvantages to each of the SOS models that it has experienced in the US and across the globe.

IV. Contact Information

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V. Conclusion

The Commission should not artificially manage the prices of SOS that were generated through long- and repeatedly-approved auction processes and lauded by many over the years as being great for customers. On one hand, policy leaders say if prices to consumers are so low that NPPs cannot compete, the system is great because consumers win. On the other hand, policy leaders say that if the process we approved yields prices we don't like, then we will "fix it" and manipulate it to an artificial price we do like. These types of actions send signals to the market that will result in negative impacts on consumers in the short-term and over a much longer time horizon and will discourage energy investment in the state. Direct Energy urges the Commission to allow the market to evolve. As pointed out above, NPPs are currently offering a variety of lower-cost and renewable energy options for immediate switching by consumers.

Direct Energy urges the Commission to take a long-term view of the electricity procurement process and related energy markets. The role of the utility and default service design will be paramount to determining the long-term success of the market. The Commission should also be clear on what its desires and expectations are of other market stakeholders including NPPs and other service providers. More immediately, Direct Energy urges the Commission to consider the implementation of several short-term retail market enhancements, which will result in more educated consumers, better tools for consumers to evaluate their energy options and manage their own energy consumption. If the Commission is compelled to interfere with the market signal, it should do so in a minimalist manner.

Regardless of the Commission's actions in direct response to the pending rate changes, Direct Energy urges the Commission to establish a process to determine what it wants the future market to look like and then set out a plan to get there. The Commission's view of the role of the utility and default service design will be paramount to determining the long-term success of the market. The Commission should also be clear on what its desires and expectations are of other market stakeholders like NPPs, distributed energy resources, energy efficiency, electric vehicles and other service providers.

Direct Energy urges the Commission to acknowledge that the current Standard Offer System is not functioning appropriately. It does not reflect the true cost to serve customers and therefore the market is biased toward utility supply instead of NPP services. Direct Energy urges to Commission to immediately implement the short-term fixes identified above and ultimately all of the market improvements that are outlined in these comments. These fixes will not prevent price spikes under a flawed SOS procurement design. They will result in more educated consumers, better tools for consumers to evaluate their energy options, and better tools for consumers to manage their own energy consumption. Direct Energy urges the Commission to enable empowered energy consumers to make responsible choices that work for their households and businesses today and for the modernized grid of the future that is on its way.

The Commission should develop a long-term plan that incorporates the suggested changes so that by the time the advanced grid and metering functionality is in place, the market will be able to provide services to drive value from those investments. By the time that smart grid capabilities have been deployed, the regulatory mindset must be one that consumers are empowered to protect themselves with tools available in the market.

Respectfully Submitted,

DIRECT ENERGY BUSINESS, LLC AND
DIRECT ENERGY SERVICES, LLC

Date: August 22, 2018

____/s/_____________________

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Its Attorney

CERTIFICATE OF SERVICE

This is to certify that on the 22nd day of August, 2018, I sent a true copy of the foregoing to the attached service list.

/s/

Joseph A. Farside, Jr.

Docket No. 4692 - National Grid – 2018 Standard Offer Service (SOS) and Renewable Energy Standard (RES) Procurement Plans
Service List updated 8/14/18

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BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

PUBLIC SERVICE ELECTRIC AND GAS

BPU Docket Nos. ER18010029 and GR18010030

OAL Docket No. PUC 01151-18

DIRECT TESTIMONY

OF

FRANK LACEY

AUGUST 6, 2018

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
FRANK LACEY
PRESIDENT AND FOUNDING DIRECTOR – ELECTRIC ADVISORS CONSULTING, LLC

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Frank Lacey. My business address is 3 Traylor Drive, West Chester, PA 19382.

Q. BY WHOM ARE YOU EMPLOYED AND ON WHOSE BEHALF, ARE YOU TESTIFYING?

A. I am an independent consultant submitting this testimony on behalf of Direct Energy Business, LLC; Direct Energy Business Marketing, LLC, Direct Energy Services, LLC; Gateway Energy Services Corporation; and RJR Retail Services Company (collectively, "Direct Energy"). Direct Energy is one of the largest competitive retail providers of electricity, natural gas and home services in North America, with over 4 million customer relationships, multiple brands and roughly 5,000 employees. As third-party energy suppliers in New Jersey, all five intervening Direct Energy companies hold electric power and/or gas supplier licenses. Direct Energy is licensed to sell natural gas and electricity to customers in PSE&G's service territory. Direct Energy and its subsidiaries also provide energy-related products and services such as the Hive home energy management system, demand response, distributed energy resources, appliance services, HVAC services, and others.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. As a consultant, I am providing policy- and market-related consulting services to advanced energy management companies and end-use customers. I have worked in the electric power industry for approximately 25 years, beginning immediately after earning my graduate degree. I have worked on major industry restructuring issues including generation asset divestiture, with a specialization in environmental asset valuation; stranded cost valuations; transmission restructuring including the development of Independent System Operators ("ISOs") and Regional Transmission Organization ("RTOs") and other independent transmission entities; the development of retail energy markets; and the development of demand response markets. Early in my career, I was employed as a consultant to industry participants, first by Putnam, Hayes & Bartlett, Inc. and then by Arthur Andersen Business Consulting. Within the industry, I have worked for Strategic Energy, a retail electricity supplier, Direct Energy, a retail energy supplier that acquired Strategic Energy in 2008, and most recently, Comverge, Inc. and CPower, two companies that shared a common owner and provide demand response services to residential and to commercial & industrial ("C&I") customers, respectively. I created Electric Advisors Consulting LLC in 2015. I hold a Bachelor of Science degree in Transportation and Logistics from the University of Maryland and a Master of Science in Industrial Administration with concentrations in finance and environmental management from the Tepper School of Business at Carnegie Mellon University. My resume is provided as Exhibit FPL-1.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL AFFILIATIONS?

A. I am currently a member of the board of directors of the Smart Electric Power Alliance ("SEPA"), a trade association with more than 1,000 members including utilities, distributed resource providers and related service providers. I am the Chairman of the Advisory Council on Demand Response and Smart Grid within SEPA, which is a standing committee dedicated to enhancing the vision of demand response and smart grid within SEPA. Prior to its dissolution in 2015, I served on the board of directors of the Association for Demand Response and Smart Grid. I am also a founding member and the current Chairman of the Advanced Energy Management Alliance. I served on the board of directors of the Electric Reliability Council of Texas ("ERCOT"), the grid operator in Texas, from 2002 to 2004.

Q. HAVE YOU EVER TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES OR ANY OTHER UTILITY REGULATORY AGENCY?

A. I have not testified before the New Jersey Board of Public Utilities ("NJBPU" or "Board"). I have, however, testified numerous times before other state regulatory agencies, legislatures, and twice as a technical conference witness at the Federal Energy Regulatory Commission ("FERC"). I recently filed an expert report on energy matters in the Superior Court of New Jersey in Bergen County. I have provided expert testimony before the utility commissions in New York, Pennsylvania, Ohio, Maryland, Massachusetts, Illinois, Delaware, Rhode Island, Virginia, Utah and California. I have presented oral testimony in less formal proceedings before the Commissions of Maryland, Pennsylvania, Delaware and Texas. I have presented legislative testimony in New York, Maryland, Pennsylvania, Delaware, Michigan, California and Texas. I have also spoken at numerous trade shows, conferences and other industry and corporate events as an expert on electricity market issues. A summary of my prior testimony is contained in Exhibit FPL-2.

Q. WHAT IS THE DIRECT ENERGY'S INTEREST IN THIS PROCEEDING?

A. Direct Energy has, among other businesses, competitive retail electric supply and competitive retail gas supply businesses operating in New Jersey. With these businesses, Direct Energy is forced to compete directly with PSEG's basic generation service ("BGS") and its basic gas supply service ("BGSS"). PSEG allocates costs that are incurred to support the retail energy businesses to the distribution businesses. Because PSEG does not allocate an appropriate amount of costs to the provision of its basic retail energy services, they are subsidized significantly by distribution rates paid by all customers, including competitive supply customers. Direct Energy is seeking an equitable allocation of what are currently classified as distribution costs to the basic retail energy services businesses of PSEG. An equitable allocation will result in rates for distribution, BGS and BGSS that are just and reasonable. It will also result in BGS and BGSS being placed on a more equal competitive position to the competitive suppliers in the market. Because BGS and BGSS are the electric and gas services that all residential and most other customers are put on when they first enter the electric market, every competitive retail supplier must compete with the BGS and BGSS offerings. Direct Energy seeks to remove the subsidies from the distribution business that artificially incentivize the customers to stay on these basic services, a result that harms the competitive market, harms customers and results in an over-consumption of energy.

Direct Energy also has an interest in a number of other issues, including, the appropriateness of subsidizing PSE&G' s appliance repair services business with distribution revenue requirements funding; the appropriateness of PSEG's proposed Green Enabling Mechanism ("GEM"); and PSEG's methodologies utilized in the procurement of natural gas supply. Direct Energy submits that these issues, among others, should be thoroughly examined in this proceeding. PSEG's filing addresses each of these other issues, but unfortunately, has proposed solutions in each of these areas that are anti-competitive and serve to harm customers and the competitive markets for energy and energy related services. My testimony will address the appropriate allocation of costs to BGS and BGSS; the appropriateness of rate payers funding PSEG's Appliance Services Business; and PSEG's GEM proposal. Direct Energy witness Mr. Orlando (Randy) Magnani will address the gas procurement issues.

To avoid any confusion, unless otherwise directly stated, any references in this testimony to PSEG refer to the electricity and gas distribution utility operating in northern New Jersey and not to any other affiliate of the utility.

II. SUMMARY AND CONCLUSIONS

Q. HAVE YOU READ PSEG'S RATE CASE FILING AND SUPPORTING TESTIMONY?

A. I have.

Q. COULD YOU PLEASE SUMMARIZE THE FILING AND YOUR CONCLUSIONS?

Yes. PSEG has filed what would be classified as a traditional utility rate case, seeking an increase in base distribution rates for its gas and electricity distribution businesses. However, on deeper review of the filing, I find that PSEG is using this rate case to ensure its continued market dominance in the provision of energy and energy-related products and services.

The revenue requirements testimony details costs, categorized and allocated into different buckets. It then suggests a rate design for each customer class to recover its requested revenue requirements which consist of projected costs and a rate of return. I take no position on the overall revenue requirement submitted by PSEG in this proceeding. However, I do find that the rate case presentation is generally not consistent with today's markets for energy and energy-related goods and services, nor is it consistent with New Jersey's clean energy goals as PSEG's proposals for the continued subsidization of its appliance services business and its underlying reasons for its GEM proposal will continue to hinder competitive efforts to offer goods and services that will help customers better manage their energy consumption.

I conclude based on my review of the filing that 1) PSEG allocates too many costs to its distribution business and fails to allocate costs appropriately to the BGS and BGSS businesses; as such, it is over-collecting its distribution costs and under-collecting costs related to serve BGS and BGSS customers, giving PSEG an undisputable anti-competitive cost advantage when serving customers retail electricity and gas; 2) PSEG is inappropriately using ratepayer funds to subsidize its Appliance Services Business, which is in direct competition with many other appliance service businesses that are not supported by ratepayer funds; and 3) the GEM proposal appropriately compensates PSEG for revenues due to energy efficiency investments. However, the underlying desires of PSEG are anti-competitive and the Board should put constraints on the GEM to ensure that the provision of energy efficiency services happens in an open and competitive manner.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. In this testimony, I recommend some changes to the structures of some of the rates proposed by PSEG. I do not request a change in – and as mentioned above, take no position on – the overall revenue requirement presented by PSEG. I will demonstrate that PSEG has allocated too many costs to the distribution businesses and as a result, the rates charged to customers for the provision of the basic commodities in BGS and BGSS are too low. The subsidized BGS and BGSS businesses don't account for many of the business costs required to operate those businesses. The artificially low costs for energy commodity service are anticompetitive and are inconsistent with appropriate cost-causation principles. To correct this glaring and overwhelming flaw in the competitive energy markets, I will propose and demonstrate that an adjustable "BGS Equality Adjustment Mechanism" ("BEAM") should be implemented and applied to all customers' distribution rates such that all revenue requirements are fully and properly recovered by PSEG and that BGS and BGSS customers are appropriately charged for receiving basic generation and gas supply services from the utility. I also present a concrete recommendation for the initial allocation of costs to BGS and BGSS. Further, I demonstrate why it is not in the public interest to continue to have PSEG's appliance service business subsidized by distribution ratepayers. Finally, I support generally the concepts outlined in the GEM proposal; however, I will reveal some of the underlying incentives for PSEG's request that should not be allowed in the market going forward.

Q. WHAT DO YOU BELIEVE PSEG'S OBJECTIVES ARE FOR DESIGNING ELECTRIC RATES?

A. According to PSEG witness Mr. Swetz, PSEG's recovery of costs "should be effectuated on an equitable basis that provides correct price signals to individual customers based on the cost to serve those customers." Swetz electric testimony (Ex. P-9E R-1), pp. 31-32; Swetz gas testimony (Ex. P-9G R-1), p. 24. In fact, Mr. Swetz further testified that he "cannot overemphasize the need for development and implementation of correct price signals to customers." Swetz electric testimony (Ex. P-9E R-1), p. 32.

Q. HAS PSEG PRESENTED RATES THAT PROVIDE THE CORRECT PRICE SIGNAL TO CUSTOMERS?

A. No. Under PSEG's proposals, distribution costs are too high and energy supply costs are too low, incentivizing an over-consumption of energy and creating anti-competitive energy markets.

Q. DOES YOUR PROPOSED BEAM FACILITATE CORRECT PRICE SIGNALS TO INDIVIDUAL CUSTOMERS BASED ON THE COST TO SERVE THOSE CUSTOMERS?

A. It does. My proposal addresses and corrects the shortfalls in PSEG's proposed rates. In the absence of a mechanism to allocate costs to BGS and BGSS such as the BEAM that I describe later, customers will not be receiving accurate price signals for either commodity or distribution service based on the cost to serve those customers.

III. ALLOCATION OF COSTS TO BGS AND BGSS

Q. DO YOU HAVE AN OPINION AS TO THE OVERALL APPROPRIATENESS OF THE REVENUE REQUIREMENTS SUGGESTED BY PSEG IN THIS PROCEEDING?

A. I have not evaluated the level of costs and elements that comprise the costs to form an opinion about their appropriateness. However, I have reviewed the rate structures proposed and I conclude that the structure of the rates themselves should be modified to include a BEAM credit on distribution bills to offset the overcollection of distribution costs that should be allocated to the BGS and BGSS businesses and a corresponding BEAM to collect those costs from BGS and BGSS customers on the energy portion of their bills. To be consistent with the cost causation principles articulated by PSEG throughout this proceeding, a representative level of costs must be allocated to the BEAM for BGS and BGSS. Collectively, the BEAM and BEAM Credit will ensure that PSEG will collect its full revenue requirements. I will explain this mechanism in further detail below.

Q. WHAT ARE BGS AND BGSS?

A. BGS and BGSS are basic generation service and basic gas supply service, respectively. These are the basic commodity services that PSEG offers to its customers who have not chosen a competitive supplier, or who for one reason or another, have left a competitive supplier and have returned to the utility to receive their commodity service. For ease of reading, my testimony will first focus on the allocation of costs to the BGS electricity business. The same facts and arguments are applicable to the BGSS business. Instead of repeating all of my arguments, analyses and positions with respect to BGSS, I will adopt my prior statements and include only a brief discussion and my conclusions with respect to BGSS.

Q. WHAT COSTS ARE PASSED ALONG CURRENTLY TO CUSTOMERS WHO TAKE BGS AND BGSS COMMODITY SUPPLY?

A. BGS costs include the cost of supply that is procured in the BGS auction. These costs include the wholesale related costs including energy, capacity, transmission, and all ancillary services. PSEG includes a monthly reconciliation charge to ensure that it does not over- or under-collect its costs related to the wholesale components of BGS service. A similar set of costs are passed through to BGSS customers. Direct Energy witness Mr. Magnani addresses these and other issues in his testimony in more detail.

Q. WOULD THE BEAM BE AN INCREMENTAL COST TO BGS CUSTOMERS?

A. It would be an incremental charge on the energy side of a BGS customer's bill, but it would be offset by a corresponding decrease in distribution rates, as described below.

Q. ARE ANY INTERNAL MANAGEMENT OR RETAIL SERVICE-RELATED COSTS THAT ARE INCURRED BY PSEG ALLOCATED TO BGS IN THE CURRENT BGS MODEL?

A. No.

Q. DOES PSEG CURRENTLY ALLOCATE ANY INTERNAL COSTS TO THE BGS BUSINESS?

A. No.

Q. ARE THESE THE TYPES OF COSTS THAT YOU WOULD INCLUDE IN THE BEAM?

A. Yes.

Q. WHY SHOULD COSTS BE ALLOCATED TO THE BGS BUSINESS?

A. Although utilities, including PSEG, that offer a basic commodity service do not typically treat the basic service business as a separate business unit, they should. On a revenue basis, based on the projections stated in PSEG's testimony, the BGS business is approximately the same size as its electric distribution business. PSEG projects that approximately 48% of its electricity revenues will come from BGS service. Table FPL-1 details the numbers presented in PSEG's testimony.

Table FPL-1: Comparison of Business Unit Projected Annual Revenues**		
Service	**Projected Revenue**	**Percent of Total Electric Revenues**
Distribution	$1,308,990,811	52.16%
BGS	$1,200,664,274	47.84%
Total	**$2,509,655,085**	**100%**

** Source: SS-E5-R1

As discussed more below, it is simply not credible to believe that a $1.2 billion business can be run without any costs associated with it.

Q. WHY SHOULDN'T THE BGS COSTS SIMPLY BE PAID FOR BY THE DISTRIBUTION CUSTOMERS IF THE PROVISION OF BGS IS REQUIRED OF PSEG?

A. For at least two primary reasons. First and foremost, because no retail costs are allocated to the BGS business, distribution rates are too high and the cost of BGS service is artificially low. That pricing incongruity gives PSEG a discriminatory cost advantage in the provision of retail electric service to customers in its service territory, which leads to several problems for customers. Customers are not able to compare, on an apples-to-apples basis, retail products offered in the market to BGS. Instead of an apples-to-apples comparison, customers today are comparing apples from the competitive retail community to something more like baked beans from PSEG. BGS is not remotely comparable to the competitive retail services provided, but PSEG (and other utilities) suggests through many avenues that the products are equivalent. Additionally, without an appropriate allocation of costs to BGS, customers who avail themselves of shopping opportunities are then forced to subsidize the costs of the customers who stay on BGS.

Second, it is common and prudent business practice to allocate an appropriate amount of costs to any business or business unit so that management can better understand the practical implications of running that line of business. According to the Corporate Finance Institute, "Cost allocation is an important process for a business because if costs are misallocated, the business might make wrong decisions to overprice/underprice a product or invest unnecessary resources in non-profitable products." Because no costs are allocated to BGS, PSEG is underpricing electricity supply, which leads to over-consumption. To determine if costs should be allocated to the business, one only has to investigate whether or not the business could sustain itself with its current cost structure if it were operated on a stand-alone basis. Clearly, the BGS business could not operate for even a single day under its current cost structure if it were operated on a stand-alone basis.

Further, PSEG cost allocation witness Mr. Swetz testified that "one objective of ratemaking is that the end result should be a reasonable one." Swetz electric testimony (Ex. P-9E R-1), p. 16. Without an allocation of costs to BGS and BGSS services, the rates for both those and the respective distribution rates are not reasonable.

Q. **IS IT REASONABLE TO ASSUME THAT A HANDFUL OF PEOPLE COULD RUN, MANAGE AND EXECUTE THE BGS BUSINESS LINE SUCH THAT AN ALLOCATION OF COSTS WOULD BE IMMATERIAL?**

A. No. It is unreasonable to expect that only a handful of people could fully and capably run, manage and execute the entire spectrum of requirements of the BGS business. In this proceeding, PSEG projects the BGS business to be a 22.5 billion kWh business. As stated above, the BGS business is expected to produce approximately $1.2 billion in revenue annually. Managing nothing more than the finances and the cash flow issues associated with the business would require more than a handful of personnel. As discussed below, BGS has also the potential for material financial impact on PSEG and it has to be managed accordingly.

Q. **IT IS BELIEVED THAT MANY OF THE COSTS IN THE DISTRIBUTION BUSINESS DO NOT GO AWAY IF CUSTOMERS CHOOSE A COMPETITIVE SUPPLIER. DOESN'T THAT SUGGEST THE COSTS SHOULD STAY IN THE DISTRIBUTION BUSINESS?**

That argument confuses the concepts of avoidable or "direct" costs with the practice of appropriate allocation of "indirect" costs. Avoidable costs should be allocated 100% to the appropriate business or business unit. Bad debt, working capital, credit costs, regulatory costs and some others would be fully avoidable if PSEG was no longer serving as the BGS provider. In other words, if any costs disappear because all customers left BGS, those costs should be directly allocated to the BGS. PSEG does not even take the simple step of allocating direct costs to the BGS business. It is noted however, that many of the costs that I believe should be allocated are not avoidable. Regardless, sound business practices require that these costs be appropriately allocated to the BGS business unit so that the BGS is priced appropriately. These costs are classified as indirect expenses or shared expenses.

Allocation of costs to different businesses or business units is not a novel concept. Companies, including PSEG in this rate proceeding, allocate indirect expenses to varying business units and cost centers on a regular basis. In fact, this rate case is premised almost entirely on allocating indirect costs to certain customers and customer classes. The failure to allocate an appropriate level of costs to BGS will result in a grossly anti-competitive pricing structure for BGS service, and rates for distribution customers that are not just and reasonable.

Q. ARE YOU SUGGESTING THAT PSEG'S REQUESTED REVENUE REQUIRMENT IN THIS PROCEEDING IS TOO HIGH?

A. As stated above, I do not offer an opinion on the appropriateness of the revenue requirement requested in this proceeding. I am suggesting that a portion of the costs that are being requested as revenue requirements should be allocated to the BEAM because these costs benefit and serve the BGS business. Without such an allocation, distribution rates will be too high as they will include costs that are incurred to support non-distribution-related businesses such as the BGS business. I will describe a cost recovery mechanism below that will keep the distribution utility financially neutral to this re-allocation and the implementation of the BEAM, regardless of the revenue requirement approved in this proceeding.

Q. WILL THE BEAM INCREASE COSTS TO CUSTOMERS?

A. Under the proposal outlined below, total consumer costs and company revenues will stay the same. In this regard, it is very similar to the GEM proposal that PSEG has put forth in this proceeding. The cost increases for BGS in total will be offset exactly by cost decreases on the distribution portion of the bill. On net, customers will pay the exact same total amount and PSEG will recover its total revenue requirement. However, as customers migrate to competitive options, those customers who remain on BGS will see a higher price for the BEAM than the BEAM Credit they receive on their bill. This outcome is reflective of an appropriate allocation of costs to customers based on cost-causation principles. This allocation is in the public interest as it results in rates for both distribution customers and BGS customers that are just and reasonable.

COST COMPONENTS ALLOCATED TO THE BEAM

Q. WHAT COSTS SHOULD BE ALLOCATED TO THE BEAM AND BGS?

A. PSEG should allocate costs from several areas of the company. In general, pieces of the executive function, the accounting and finance function, the regulatory function, the billing and call center functions, the metering function, the marketing function, and almost any other function outside of costs that are strictly related to the "poles and wires" part of the distribution business, should be partially allocated to the BGS function.

Q. ARE THESE COSTS EASILY IDENTIFIABLE IN THE DOCUMENTS PRESENTED IN THIS RATE PROCEEDING?

A. At a high level, they are easily identifiable. At a very granular level, they are not. As such, I have had to make educated assumptions and allocations based on my experiences over 25 years working in this industry, based on sworn testimony from PSEG witnesses in this proceeding, and based on the definitions in the FERC Uniform System of Accounts.

Q. WHAT COST CATEGORIES DID YOU INCLUDE IN YOUR ANALYSIS OF COSTS ALLOCABLE TO THE BEAM AND THE BGS BUSINESS?

A. I have included costs related to the headquarters, services, meters, general plant, common plant, intangible plant, rents, customer care and collections, billing, advertising, sales, insurance, injuries, A&G, employee benefits, working capital and taxes other than income taxes.

Q. WHY DID YOU CHOOSE THESE CATEGORIES OF COSTS TO INCLUDE IN YOUR ALLOCATION?

A. Because the BGS business would not be sustainable if these resources were not utilized to support the business.

Q. ON WHAT BASIS DID YOU ALLOCATE COSTS TO DETERMINE YOUR PROPOSED ALLOCATION TO BGS.

A. I allocated costs to the BEAM and BGS business unit using revenues to determine the allocation. I considered using customer count as an allocator, but customers do not fall into either "BGS" or "distribution" categories. Approximately 90% of the residential customers are customers of both the BGS and distribution businesses. If I used customer count as an allocator, I would then have to apply a second allocator, which would most appropriately be revenue. Because 90% of the customers are customers of both business units, the difference between the two approaches would be *de minimis*.

Q. CAN YOU EXPLAIN WHY REVENUE IS AN APPROPRIATE ALLOCATOR FOR THESE COSTS?

Revenue is the best allocator for many of these costs. Customer care, billing, collections, metering, advertising, sales, working capital, taxes and other related costs are directly tied to the revenue or the revenue function of the business. A meter, for example, measures kilowatt hours of electricity usage, which is used to collect two revenue streams from BGS customers. A labor-based allocation might be better for A&G costs, for example. However, labor records were not part of PSEG's presentation in this proceeding. Given the lack of any better allocator such as hourly labor data, revenue is the best allocator of costs to the different business units.

Q. WHY DO YOU BELIEVE THAT AN ALLOCATION OF A&G EXPENSES IS APPROPRIATE?

As I mentioned above, BGS is a $1.2 billion business that ties up a significant amount of working capital and has potential ramifications on the company's credit ratings. These are issues that are germane to shareholders, bondholders, banks and others in the financial services sector. In other words, BGS places several risks on the utility, but offers no potential for earning a return (other than the returns on the distribution assets used to support the BGS business). Being such an important and risky piece of the business, it is difficult to comprehend that the senior leadership of the company doesn't spend a material amount of time over the course of a year discussing these issues, whether internally or with external stakeholders, such as those in the financial community. As evidence of the potential importance to the company, the words "BGS" or "BGSS" appear in PSEG's most recent 10k filed with the US Securities and Exchange Commission over 100 times. It is clear from that alone the magnitude of effort required to operate the BGS business. Employees throughout the utility organization are constantly working on BGS-related issues.

Q. IS IT POSSIBLE TO APPROPRIATELY ALLOCATE COSTS TO THE BASIC SERVICE BUSINESS?

A. Not only is it possible, it should be required. The BGS business should be functionally separated from the distribution business and an appropriate level of costs should be allocated to it and recovered from BGS customers.

Q. WOULD AN APPROPRIATE ALLOCATION OF COSTS TO THE BGS BUSINESS FACILITATE A MORE COMPETITIVE ELECTRICITY MARKET?

Yes. It would. It would give customers the opportunity to make more informed comparisons of costs between BGS and competitive supply options. Retail suppliers have significant cost structures that PSEG also has, but PSEG's BGS prices do not reflect these costs because they are inappropriately borne by distribution ratepayers. The BEAM allocation would add an additional level of transparency to the market for customers.

Q. DO YOU HAVE A CONCRETE RECOMMENDATION FOR THE BOARD TO CONSIDER?

I do. I will first detail the BEAM approach that will ensure that PSEG is always fully compensated for its revenue requirement. I will then discuss the appropriate dollar amounts to be allocated to the BEAM and BGS business.

BEAM MECHANICS

Q. COULD YOU PLEASE DESCRIBE THE BEAM MECHANICS?

A. BGS is a dynamic service. Customers move onto and off of BGS. The BEAM, therefore, needs to be flexible to ensure PSEG will not over- or under-collect its revenue requirements. The BEAM is designed with attributes that are very similar to PSEG's GEM proposal. Two new bill components are needed for efficient and fair implementation of the BEAM. These are BEAM and the BEAM Credit. The BEAM is a charge that is applied on the energy side of the customer's bill. The BEAM Credit represents a reduction in costs and is applied to the distribution side of the bill. The total of BEAM revenues plus BEAM Credits should always balance to zero, thus ensuring that PSEG does not over- or under-collect it revenue requirements. The BEAM credit should be applied to every customer taking distribution service. The BEAM charge reflects the appropriate allocation of costs to support the BGS business and is applied only to customers taking BGS service.

At the start of the program, PSEG's distribution rate will be what the Board determines it to be, based on the outcome of this proceeding. That will be reflected on the customers' bills. In month 1, when the total BEAM is determined (assume for now, $10 million per month), that charge would be applied to all BGS customers on a per-kWh basis, which would result in PSEG over-collecting its revenue requirement that month by $10 million. So, PSEG would deploy the BEAM Credit on all distribution customers. The credit would also be applied on a per-kWh basis such that the credit resulted in $10 million in refunds to all distribution customers (including those on BGS service who paid the BEAM). If all customers were on BGS service, the BEAM charge and BEAM Credit would be exactly the same for every customer.

If after determining a new allocation of costs in a subsequent period, the BEAM decreases by $500,000, the BEAM Credit would also adjust by $500,000. Because of mid-month customer migration and the timing of procurements, and other issues, in any given month, the forecast BEAM and associated credit might be different from the actual requirement and collection. PSEG should be allowed/required to make true-up adjustments in the following month to recover/refund the under/over-collection, just as they would under its GEM proposal.

Q. UNDER YOUR PROPOSAL, PSEG WOULD BE ALLOCATING MILLIONS OF DOLLARS TO THE BGS RATES. HOW DOES PSEG RECOVER THESE REVENUE REQUIREMENTS IF AND WHEN CUSTOMERS MOVE TO COMPETITIVE SUPPLY?

Because the BEAM costs are allocated based on BGS revenues, PSEG is unaffected by customer migration on and off BGS service. As customers move from basic service to the competitive market the allocation ratio of costs to the BEAM, the BEAM and the corresponding BEAM Credit will be reduced – and PSEG would continue to recover 100% of any costs it has been authorized to charge. For example, suppose only 5% of the customers remained on BGS service. Only 5% of the costs that I have identified as BGS-related would be allocated to the BEAM. So instead of the hypothetical $10 million in the first month with 90% of the customers on BGS, the BEAM charge would be approximately $500,000 if only 5% of the customers were on BGS. The corresponding BEAM Credit would also be an offset of an equal amount. The per-customer BEAM should not adjust much over the life of the program. The BEAM credit will decrease as customers move to competitive supply. If 100% of all customers took competitive electricity supply, the BEAM credit and BEAM would go to zero. In this scenario, the realized distribution rate to all customers would then be at exactly the level that the commission approved in this proceeding.

Q. HOW OFTEN WOULD YOU RECOMMEND CHANGING THE ALLOCATION?

A. I would not change the allocation methodology once it is set. I would adjust the allocation amount monthly as required to keep the price fair to BGS customers, distribution customers, PSEG and the competitive market participants.

Q. ARE YOU CONCERNED THAT THE MONTHLY CHANGES WOULD BE DISRUPTIVE TO CUSTOMERS?

A. For a several reasons, no. If implementation of the BEAM leads to customer migration away from BGS service, the BEAM allocation will decrease in proportion to the decrease in BGS revenues. The change in aggregate might be material, but the change to the customers remaining on BGS service should be close to no change at all. More importantly, the changes, if they occur would apply to only a very small portion of a customer's total bill. As for the adjustments on the distribution side, they will be insignificant to the customer compared to all of the changes that occur on a regular basis on their bill, and the adjustments to the distribution bill will always be negative (or zero) price adjustments. In no instance will a customer see a distribution bill higher than what is authorized by the Board in this proceeding. To put the magnitude of the BEAM in perspective, this rate case is seeking a $200 million (17.8%) general rate increase on distribution rates that will now total $1.3 billion. The entirety of the proposed BEAM (which only represents a re-allocation of costs and not a revenue increase) is less than the amount sought as an increase by PSEG and will result in price changes (at most) of only small fractions of a penny per kWh monthly. Further, PSEG is also suggesting that distribution revenue requirement per customer could be increased by as much as 6.5% annually under the terms of their GEM proposal. BEAM adjustments will be a fraction of that amount.

I present concrete examples of changes in rates below. Again, on net, customers in total will be paying the exact same amount. PSEG will recover its revenue requirement in full. Some of that will be recovered by BGS customers. The "over-recovery" will be credited back to all distribution customers. If customer choice ever gets to 100%, the BEAM Credit and BEAM would go to zero.

Q. CAN YOU PLEASE PROVIDE AN EXAMPLE OF HOW THIS BEAM AND BEAM CREDIT RESULT IN ENSURING THAT PSEG DOES NOT OVER- OR UNDER-COLLECT?

A. Yes. Table FPL-2 shows how this mechanism would work when implemented. The numbers presented in this table are not actual numbers from the rate case. Rather, they are just numbers, at approximate scale, selected to show how the BEAM tool could work. This chart classifies 30% of the distribution revenue requirement as "allocable" to BEAM (column "e"). That amount is then allocated to BEAM based on the revenue split between BGS and distribution (column "i"). To simplify this chart, the allocation in this step is based on the number of customers taking BGS versus those on competitive supply. It is not based on actual revenues. Under this approach, in the first row of the Table showing no retail choice customers, 50% of the allocable costs are assigned to the BEAM and the other 50% stay with the distribution business. The power of this tool is that as competitive shopping increases, the allocation of costs decreases, commensurate with the change in revenues to PSEG. As a result, the BEAM and BEAM Credit also get smaller (column "k"). In the scenario with only one customer remaining on BGS, the BEAM cost allocation approaches zero.

If implemented correctly, PSEG will always exactly collect its revenue requirement (columns "d", "m" and "n").

Table FPL-2: Sample Calculations Showing Impact of BEAM and BCAM Credit on PSEG Revenue Collections

Time Period	Number of Dist Customers	Average Dist Kwh/cust/ month	Total Dist Revenue Requirement ($)	Distribution costs allocable to BGS (30% of all costs)	Retail Choice Customers	BGS Customers	Revenue-based Allocation Ratio to BEAM	Costs Allocated to BEAM	BEAM per BGS Customer ($/month)	Total BEAM and BEAM Credit	BEAM Credit per Dist customer ($/month)	Total Distribution Collections ($)	Variance from Total Rev Req.
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]	[n]
0	1,600,000	577	46,160,000	13,848,000	-	1,600,000	0.50	6,924,000	4.33	6,924,000	4.33	46,160,000	$0.00
1	1,600,000	577	46,160,000	13,848,000	200,000	1,400,000	0.41	5,654,600	4.04	5,654,600	3.53	46,160,000	$0.00
2	1,600,000	577	46,160,000	13,848,000	800,000	800,000	0.17	2,308,000	2.89	2,308,000	1.44	46,160,000	$0.00
3	1,600,000	577	46,160,000	13,848,000	1,000,000	600,000	0.10	1,416,273	2.36	1,416,273	0.89	46,160,000	$0.00
4	1,600,000	577	46,160,000	13,848,000	1,599,999	1	0.00	0	0.00	0	0.00	46,160,000	$0.00

BEAM RECOMMENDATION

Q. HAVE YOU PERFORMED AN ANALYSIS THAT SUPPORTS A RECOMMENDATION FOR ALLOCATING COSTS TO THE BEAM?

A. I have.

Q. WHAT DO YOU BELIEVE IS THE APPROPRIATE LEVEL OF COSTS TO BE ALLOCATED TO THE BEAM?

Based on the data available in this proceeding, the BEAM amount should be set initially at $119 million annually for residential customers and should initially be $71 million annually for C&I customers.

Q. CAN YOU EXPLAIN HOW YOU ARRIVED AT THOSE NUMBERS?

Yes. I reviewed all of the cost elements in PSEG's rate case and I determined that several of the cost elements were used to facilitate service to BGS customers. I relied on PSEG's allocation of those costs to different customer classes. I added up all of the costs that I believe are applicable to BGS service and then applied the revenue allocation factor to those costs and arrived at the numbers in the tables below. Table FPL-3 details the BEAM cost buildup for the residential customers.

Table FPL-3: Cost components for Residential Electric BEAM (rate classes RS, RHS, and RLM)	
Return on Ratebase	$18,354,984
Working Capital	$10,007,525
Expenses	$90,549,036
Total	**$118,911,545**

Table FPL-4 details the BEAM cost buildup for the C&I customers.

Table FPL-4: Cost components for C&I Electric BEAM (all other rate classes)	
Return on Ratebase	$9,813,587
Working Capital	$8,757,384
Expenses	$52,613,550
Total	**$71,184,521**

Q. HOW DO THESE NUMBERS TRANSLATE TO A PER-KWH BASIS?

PSEG's filing suggests that approximately 11.9 billion kWh of BGS is sold to residential customers. That leads to an initial BEAM of $0.0100 per kWh for residential BGS customers. The corresponding initial BEAM Credit would be $0.0090 per kWh for all residential distribution customers. A BGS customer with monthly usage of 580 kWh would see a BEAM charge of $5.80 on the energy portion of their invoice. That same customer would see a BEAM Credit of $5.19

on the distribution portion of their invoice. The net increase to the average residential BGS customer, therefore would only be $0.61 per month.

The non-residential BEAM should be $0.0067 per kWh for all non-residential BGS customers. The corresponding BEAM Credit would be $0.0026 per kWh for all non-residential distribution customers.

If the Board thought it was more appropriate, these BEAM and BEAM credit calculations could be further refined for specific rate classes.

Q. WHY ARE YOU SUGGESTING THIS NOW?

A. The retail energy markets continue to evolve. As they stand now, it is clear that the elevated distribution rates are harming competitive energy markets and therefore are harming customers. During the early transitional years, competitive retail companies were learning how to operate in the competitive markets. The dynamics were such that most of the companies were focused on serving the larger customers. Alternative services like bill aggregation, demand response, and others provided significant value to the market. On the wholesale side of the market, the transition years saw the runoff of legacy contracts, market volatility and other anomalies that allowed the retail community to avail themselves of certain limited windows of opportunities, especially for residential customers. During those years, there was a constant plea from regulators for competitive suppliers to serve the residential side of the market. Now, the markets are mature. BGS pricing is stable. The wholesale markets are stable. BGS, the way it is structured today, is essentially a wholesale service being provided to retail customers, which penalizes distribution customers, especially those who have opted for a competitive supply option. With all market participants now buying from the same mature wholesale market, the infrequent "windows of opportunity" for retail sales have closed. It is now time for PSEG to price BGS as the retail service that it is, for until that is accomplished, PSEG will have a clear and discriminatory advantage in the markets and its distribution customers, particularly those who have chosen a competitive supply option, will be unfairly funding BGS customers' rates. Additionally, the BGS customers will be harmed as they will never be able to accurately assess any of the other supply options presented to them. I am not recommending any program, cost, fee or mechanism that in any way disadvantages PSEG or any other market participant. I am only recommending that the Board require PSEG to act in a fair and non-discriminatory manner in its pricing and provision of distribution services and BGS.

Q. IS THIS JUST A PLOY TO INCREASE RATES SO THAT COMPETITIVE SUPPLIERS HAVE MORE OPPORTUNITY TO COMPETE?

A. No. Notably, the majority of any cost increase on any one customer is offset by the corresponding distribution credit that will reduce the customer's costs on the distribution side of the bill. This proposal allocates costs appropriately to different lines of businesses. Under the specific proposal outlined above, residential BGS customers will see a one-tenth of one cent increase in their total bill. That equates to an additional $6.92 per year or an approximate 0.5% (one-half of one percent) increase in the annual cost of a typical residential BGS customer. By comparison, with this rate proceeding, PSEG is seeking to add $84.24 in annual distribution costs to all residential customers. PSEG is also seeking approval of its GEM proposal which might increase the distribution revenue requirement by up to 6.5% annually, which equates to a total bill increase of approximately 1.4%, which is approximately three times higher than any BEAM impact.

Further, this is the appropriate method to allocate costs that are currently not allocated to a very significant business unit within PSEG – one that accounts for approximately half of its total electricity revenues, and one that competes directly with other market participants. This type of allocation is in the public interest, reflects sound public policy, utility economics and ratemaking principles, and results in rates for both distribution and BGS customers that are just and reasonable. The implementation of these allocations has been discussed in different markets since the opening of retail choice. However, various Commissions decided that until the markets were more mature, this granular level of allocations were not needed. Now is the time that the granular level of allocations is needed.

APPLICABILITY TO BGSS

Q. YOUR TESTIMONY THUS FAR IS FOCUSED PRIMARILY ON THE BGS BUSINESS. WOULD YOU SUGGEST THE SAME ALLOCATION APPROACH FOR THE BGSS BUSINESS?

A. Yes. I would suggest the same type of allocation be applied to the BGSS business. The same logic and arguments presented above apply to BGSS and should be applied here with respect to the gas supply business. I adopt all of those same arguments here and incorporate them into this testimony as they would apply to BGSS.

Q. HAVE YOU RUN A SIMILAR ANALYSIS FOR A GAS ALLOCATION?

A. I have. The results are presented in Table FPL-5. Approximately $245 million in costs should be reallocated from the distribution business to the BGSS BEAM. About $201 million should be applied to the residential BEAM and approximately $44 million should be applied to the C&I BEAM. The respective BEAM and BEAM Credits for the rate classes are $0.1418 and $0.1353 per therm for residential customers and $0.0571 and $0.0202 for C&I customers. The total bill impact of this allocation to the average residential BGSS customer who consumes 910 therms of gas per year is equal to $5.91, or 0.7% (seven-tenths of one percent) of the customer's annual bill. As stated above, this allocation is appropriate and in the public interest. It adds transparency to the costs that BGSS customers impose on PSEG.

Table FPL-5: Proposed Allocation of Costs to BGSS BEAM			
Class	BEAM ($)	BEAM Charge ($/therm)	BEAM Credit ($/therm)
Residential	$201,002,244	$0.1418	$0.1353
Non-Residential	44,242,118	$0.0571	$0.0202

IV. THE APPLIANCE SERVICES BUSINESS

Q. IS IT APPROPRIATE FOR A REGULATED UTILITY TO RUN AN APPLIANCE SERVICES BUSINESS?

A. For a variety of reasons, it is not.

Q. HAVE YOU REVIEWED MR. JENNINGS' TESTIMONY IN SUPPORT OF PSEG'S APPLIANCE SERVICE BUSINESS?

A. I have.

Q. WHAT WAS YOUR REACTION TO HIS TESTIMONY?

A. I found his continued support of the Appliance Services Business with ratepayer funds to be rather unconvincing.

Q. COULD YOU EXPLAIN WHY?

A. Certainly. First, PSEG witness, Mr. Jennings argues that PSEG's appliance service business "provides earnings that are used directly for the benefit of our customers, reducing their cost of service." Jennings Testimony (Ex. P-2), p. 43. This statement is made in support of earning a rate of return that is at the higher end of the range of reasonableness for utility earnings. An increase in allowed returns by just one-tenth of one percent increases the revenue requirement on rate base by about $10 million. This more than offsets any gain attributed to the appliance services business.

Mr. Jennings also states that the majority of the Appliance Services Business work "is performed utilizing PSE&G's workforce with the exception of the water heating replacement work, which is performed by contractors…" Jennings testimony (Ex. P-2), p. 61. The full financial results of the Appliance Services Business were not presented in the filing, so I have not determined if labor hours are allocated correctly to the business and whether the results allocated to customers is accurate. Despite the uncertainty in the numbers, according to Mr. Jennings, the allocations of margins required by the NJ Administrative Code "reduces gas margin in this case by approximately $15.3 million and increases electric margin by approximately $7.7 million. After adjusting for tax effect this results in an increase to operating income of $5.5 million for electric and a decrease of $11.0 million to operating income for gas." Jennings testimony (Ex. P-2 R-1), P. 30. Although worded somewhat awkwardly, this suggests a <u>rate increase</u> to some customers because of the operations of the Appliance Services Business. This is not a customer benefit.

Q. DOES IT MAKE SENSE TO YOU THAT THE OPERATIONS OF AN APPLIANCE SERVICES BUSINESS WOULD RESULT IN RATE INCREASES TO CUSTOMERS?

A. It makes perfect economic sense. Conversely, it does not make public policy sense. PSEG is using ratepayer dollars to fund labor resources for the Appliance

Services Business. Mr. Jennings refers to the PSEG workforce as if it is a given that it exists and would continue to exist "as is" without the Appliance Services Business. It would not. In the absence of the appliance services business, the PSEG workforce would be smaller, so base rates would be lower. The accounting maneuvering required by the NJ Administrative Code only makes the business more transparent. It does not guarantee a customer benefit.

Q. SHOULD PSEG BE ALLOWED TO REMAIN IN THE APPLIANCE SERVICES BUSINESS?

A. It should not. As discussed above, the market for energy and energy related services has changed. Many companies operating in the competitive markets offer appliance services. These companies range from local HVAC repair companies, to some of the established chains, like Sears. And now, energy suppliers, including Direct Energy have competitive affiliates that provide appliance services. It is time for the Board to order PSEG to functionally separate or divest its Appliance Services Business. It should be noted that N.J.A.C. 14:4-3.6, cited by Mr. Jennings, is about how utilities manage and account for competitive businesses. The code section begins: "Except as provided for in the Act or this subchapter, an electric and/or gas public utility … shall not offer competitive products and/or services without the prior review and approval by the Board…" N.J.A.C. 14:4-3.6(a) (Emphasis added). Clearly, the first order priority is to not allow the utility to have a competitive business. PSEG is already operating within the "exceptions" to the primary rule. There is no sound public policy reason to continue this exception. Mr. Jennings notes in his testimony that

PSEG is the only utility in NJ to continue to have an appliance services business within the utility structure. Jennings testimony (Ex. P-2), p. 45. I would reason that it makes more sense to remove the appliance services business from the distribution business and have a competitive entity offer the appliance services, instead of saddling ratepayers with more risk. It appears that the other utilities in New Jersey have already adopted this position.

Q. ASIDE FROM THE COMPETITIVE MARKET IMPACTS, ARE THERE ANY OTHER FACTORS THAT THE BOARD SHOULD CONSIDER WHEN DECIDING IF PSEG SHOULD BE ALLOWED TO KEEP ITS APPLIANCE BUSINESS WITHIN THE REGULATED UTILITY?

A. Yes. As eloquently stated by Mr. Jennings, "PSE&G's customer base is generally fully penetrated and saturated with the currently permissible ASB offerings. As a result, there is little upside potential for this business and <u>significant risk that PSE&G will lose money</u> if the ASB program generates less than the margin flowed back to rate payers through this base rate case." Jennings testimony, (Ex. P-2) pp. 62-63 (Emphasis added). Mr. Jennings is using these risk factors to argue for a higher rate of return. Instead, the Board should acknowledge that these business risks are not the type of risks that distribution ratepayers should be funding. If Mr. Jennings believes that a higher return is warranted as a result of this business, then PSEG should unbundle the business from the utility and seek to earn those higher returns in the competitive market. Instead, PSEG is asking for a higher rate of return because of the business and expects to make "a separate filing with the Board that will propose new ASB offerings in an effort to create upside potential for managing this business." Jennings testimony (Ex. P-2), p 63.

V. GEM

Q. ARE YOU FAMILIAR WITH THE GREEN ENABLING MECHANISM OR "GEM" PROPOSAL PUT FORTH BY PSEG IN THIS PROCEEDING?

A. I am.

Q. COULD YOU PLEASE DESCRIBE YOUR UNDERSTANDING OF THE GEM PROPOSAL?

A. Yes. It is a fairly straight-forward decoupling mechanism, meaning that PSEG's distribution revenues are decoupled from its energy sales or "throughput" on the distribution systems. PSEG is seeking to implement the GEM on both its electricity and gas distribution systems. If implemented correctly, PSEG will realize and recover its full revenue requirements regardless of customers' investments in energy efficiency technologies.

Q. DO YOU SUPPORT THIS TYPE OF DECOUPLING MECHANISM?

A. Generally, I support decoupling, especially in restructured energy markets where consumers' behaviors are more unpredictable than in the vertically integrated energy markets. I believe that the industry in general needs a financially healthy and <u>unbiased</u> utility to facilitate many of the transactions that occur in an energy market. In the context of a general rate proceeding, I support the GEM proposal. However, PSEG has offered testimony in this proceeding that gives me concern about PSEG's motives for seeking the GEM and this testimony suggests that PSEG will not be an unbiased market participant moving forward.

Q. COULD YOU PLEASE EXPLAIN IN MORE DETAIL?

A. Yes. PSEG witness Mr. Jennings introduced the GEM proposal and the supporting testimony of GEM by Dr. Hansen in his testimony. Of course, Mr. Jennings testified to the revenue neutrality features and some of the societal benefits of incorporating GEM, all of which are important. Unfortunately, Mr. Jennings continues on to testify that "PSE&G plans to propose a larger Clean Energy Future ("CEF") program in 2018 that will greatly expand its investment in Energy Efficiency ("EE") programs as well as related State policy objectives, in the expectation that the GEM will be approved in this filing and can support implementing that EE program." Jennings Testimony (Ex. P-2), p. 54. Dr. Hansen confirmed "PSE&G's intention to implement a large set of energy efficiency programs." Hansen testimony (Ex. P-10), p 3. I find these plans troubling because PSEG is not including any information about their efficiency goals with this filing. While I support energy efficiency initiatives, I believe we are long past the time where the utility should be monopolizing energy efficiency dollars. On the one hand, PSEG is taking money from all ratepayers and investing it with a certain set of customers. On the other hand, PSEG is protecting themselves with its GEM proposal from the results of the investments they are facilitating in efficiency. This circular protection that is being suggested by PSEG will lock the utility in as the monopoly supplier of energy efficiency products and services. I support the decoupling, but I do not support PSEG's monopoly power over the energy efficiency market and funding. I understand that this issue is not being litigated in this proceeding. However, I believe in this proceeding, the Board could and should put limitations on future energy efficiency funding as a condition of approving the GEM.

Q. WHAT CONDITIONS WOULD YOU RECOMMEND THE BOARD IMPOSE ON EE INVESTMENTS IF THEY APPROVE THE GEM?

A. The Board should require that all future EE investments are made through third parties and not by PSEG. PSEG can be the conduit for any energy efficiency funding, but it should outsource the roles of program management, funding and implementation of efficiency programs. The funding should be allocated to competitive EE providers – firms like Direct Energy and its peers in the EE market. It is not equitable for PSEG to preclude other service providers from the market by virtue of the fact that they can collect rate payer funds to subsidize energy efficiency investments and at the same time, be held revenue neutral for reductions in energy that they create.

VI. CONCLUSION

Q. CAN YOU PLEASE SUMMARIZE YOUR TESTIMONY?

PSEG has filed what appears to be a traditional utility rate case, seeking an increase in base distribution rates for its gas and electricity distribution businesses. However, on deeper review of the filing, I find that PSEG is using this rate case to ensure its continued market dominance in the provision of energy and energy-related products and services.

First, PSEG allocates too many costs to its distribution business and fails to allocate costs appropriately to the BGS and BGSS businesses. As such, it is over-collecting its distribution costs and under-collecting costs related to serve BGS and BGSS customers, giving PSEG an undisputable anti-competitive cost advantage when serving customers retail electricity and gas. The Board should require PSEG to implement the BEAM that I discussed extensively in this testimony.

Next, PSEG is inappropriately using ratepayer funds to subsidize its Appliance Services Business, which is in direct competition with many other appliance service businesses that are not supported by ratepayer funds. This business is operating under the exceptions to N.J.A.C. 14:4-3.6. PSEG's own witness testified that none of the other utilities in New Jersey operate appliance services businesses. The Board should require PSEG to unbundle or divest its appliance service business, consistent with what the other utilities in New Jersey have already done.

Finally, the GEM, if implemented in an unbiased manner, would appropriately compensate PSEG for lost revenues due to energy efficiency investments. However, the underlying desires of PSEG as described by their witnesses in this proceeding are anti-competitive and will limit the amount of energy efficiency achieved in the state. If the Board adopts the GEM, it should apply constraints on the approval such that PSEG cannot monopolize the energy efficiency business going forward. To accomplish this goal, the Board should limit PSEG's role in energy efficiency to that of the funding conduit. Program administration and implementation should be outsourced to competitive market participants.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit FPL-1

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Summary

Recognized executive known for developing innovative regulatory and business strategies to support emerging energy market products and services. Strong knowledge of regional energy markets, market trends and national energy policy.

Board of Directors positions: Smart Electric Power Alliance (finance committee) (2015-present); Association for Demand Response and Smart Grid (finance chair) (2011-2015); Advanced Energy Management Alliance (Chairman) (2012-Present); ERCOT (finance committee) (2002-2004); Electric Power Supply Association (2002-2004).

Experience

Electric Advisors Consulting 2015- Present
Founder and President

Advise senior leadership on developing strategies to address legislative, regulatory and market design changes in the energy industry. Also provide expert testimony to advise and assist entities on facilitating legislative, regulatory and market changes to accommodate evolving business strategies and technologies.

Comverge, Inc./CPower Corporation 2011-2015
Senior Vice President, Regulatory and Market Strategy

Served on companies' executive teams, developing and implementing corporate and regulatory strategy, including M&A analyses and due diligence, market entry plans and complex communications for entities with a combined $150 million in revenue from demand response services in the electricity markets.

Direct Energy 2006 - 2011
Director, Complex Transactions (2008-2011)

For a multi-billion dollar retail electric and gas company, led team consisting of four direct reports and eight cross-functional leaders, facilitating incremental gross margin sales from non-standard product requests.

Director, Government and Regulatory Affairs (2006-2008)

Managed regulatory strategy and regulatory risk in Mid-Atlantic region of US, participating in multiple rate proceedings and regulatory initiatives, securing shareholder value through reduced credit and collateral exposure and increased sales.

Starlight Energy 2004 - 2006
President

Led the development of business plan and pro formas for venture seeking $20 million in equity financing and other financial relationships. Successes included securing $100 million credit relationship and working capital financing to enable launch of competitive electricity markets retail supply company.

Strategic Energy 2001- 2004
Director, Regulatory Affairs,

Served on the company's Leadership team, managing a regulatory group of 15 people. Managed the development of regulatory strategy, the oversight of regulatory risk and the attainment of desired regulatory results, advocating for market design structures in emerging electricity markets across 16 states and the federal government.

Arthur Andersen 1998 - 2001
Senior Manager

Responsibility for development and growth of Andersen's transmission restructuring business in Eastern half of US market.

Putnam, Hayes and Bartlett, Inc 1995 - 1998
Associate Consultant

Associate consultant in firm's energy practice with expertise in environmental asset valuation.

Education

Carnegie Mellon University, Tepper School of Business
MSIA with concentrations in finance, entrepreneurship and environmental management

University of Maryland
B.S. in Transportation and Logistics

Programs for Life
Certified Leadership Development Trainer

Prepared Direct Testimony of Frank Lacey On Behalf of Strategic Energy, LLC, before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. June 6, 2002.

Prepared Rebuttal Testimony of Frank Lacey On Behalf of Strategic Energy, LLC before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. June 20, 2002

Cross Examination testimony of On Behalf of Strategic Energy, LLC before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. July 2002.

Prepared Testimony of Frank Lacey on the subject of truing up the CERS Fee On Behalf of Strategic Energy, LLC before the Public Utilities Commission Of the State Of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. March 19, 2003

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v.Duquesne Light Company*, Docket Nos. R-00038092, R-00038092C0001 and R-00038092C0002. January 2003.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Strategic Energy L.L. C. Before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001 and R-00038092C0002. February 2003.

Prepared Supplemental Testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001, R-00038092C0002. November 2003

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001, R-00038092C0002. July 1, 2003.

Prepared Direct Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. May 19, 2003.

Prepared Supplemental Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. June 12, 2003.

Deposition Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. May 2003 and June 2003.

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. June 2003.

Oral Testimony of Frank Lacey before the Standing Committee on Energy of the New York State Assembly on the issue of Ensuring a Reliable Supply of Electricity to the People of New York, Chairman Paul D Tonko, presiding. March 6, 2003

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. February 2004.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. February 2004.

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. April 1, 2004.

Oral Testimony of Frank Lacey at the *POLR Roundtable* before the Pennsylvania Public Utility Commission re: Optimal Future POLR Design models. May 3, 2004.

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. and Mid-American Energy Company before the Public Utilities Commission of Ohio in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 6, 2003.

Deposition of Frank Lacey in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 2003.

Cross Examination Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. and Mid-American Energy Company before the Public Utilities Commission of Ohio in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case

No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 18, 2003.

Oral Testimony of Frank Lacey before the Michigan Senate Committee on Technology and Energy on the subject of revision to Public Act 141, the Michigan Electricity Choice and Restructuring Act, Chairman Bruce Patterson, Presiding. May 19, 2004.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland Senate Finance Committee on Senate Bill 561 on the subject of communications between electric companies and suppliers to enhance the development of competitive electric markets, Chairman Thomas Middleton, Presiding. March 7, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland Senate Finance Committee on Senate Bills 814, 1048, 1051 and 1078 on the subject of retail electricity market design, Chairman Thomas Middleton, Presiding. March 14, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland House of Delegates Economic Matters Committee on House Bills 1334, 1654 and 1712 on the subject of retail electricity market design, Chairman Dereck Davis, Presiding. March 14, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utility Commission in the Matter of *Petition of Direct Energy Services, LLC for Emergency Order*, Docket No. P-00062205, April 11, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utility Commission in the Matter of *Policies to Mitigate Potential Electricity Price Increases*, Docket No. M-00061957, June 22, 2006.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, July 7, 2006. (Case Settled)

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, August 2, 2006. (Case Settled)

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, August 16, 2006. (Case Settled)

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan*, Docket No. P-00062227, November 15, 2006.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan*, Docket No. P-00062227, December 6, 2006.

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan*, Docket No. P-00062227, December 15, 2006.

Oral Rejoinder Testimony and Cross-examination of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan*, Docket No. P-00062227, December 15, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania House of Representatives, Consumer Affairs Committee, Honorable Joseph Preston Jr., Chairman, March 15, 2007.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010*, Docket No. P-00072247, March 29, 2007. (case settled)

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010*, Docket No. P-00072247, April 12, 2007. (case settled)

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010*, Docket No. P-00072247, April 20, 2007. (case settled)

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, March 28, 2007.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, April 11, 2007.

Oral Surrebuttal Testimony and Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, April 19, 2007.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania House of Representatives Republican Policy Committee, Honorable Michael Turzai, Chairman, March 17, 2008.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of West Penn Power Company dba Allegheny Power for Approval of its Retail Electric Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period, Docket No.* P-00072342, February 12, 2008.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of West Penn Power Company dba Allegheny Power for Approval of its Retail Electric Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period, Docket No.* P-00072342, March 11, 2008.

Prepared Sur-rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of West Penn Power Company dba Allegheny Power for Approval of its Retail Electric Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period, Docket No.* P-00072342, March 25, 2008.

Oral Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of

Petition of West Penn Power Company dba Allegheny Power for Approval of its Retail Electric Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period, Docket No. P-00072342, April 2, 2008.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Pennsylvania Public Utility Commission in the matter of the *Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code approving a change of control of West Penn Power Company And Trans-Allegheny Interstate Line Company,* Docket Nos. A-2010-2176520 and A-2010-2176732, August 17, 2010

Prepared Sur-Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Pennsylvania Public Utility Commission in the matter of the *Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code approving a change of control of West Penn Power Company And Trans-Allegheny Interstate Line Company,* Docket Nos. A-2010-2176520 and A-2010-2176732, October 1, 2010.

Oral Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Pennsylvania Public Utility Commission in the matter of the *Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code approving a change of control of West Penn Power Company And Trans-Allegheny Interstate Line Company,* Docket Nos. A-2010-2176520 and A-2010-2176732, October 5, 2010.

Oral Testimony of Frank Lacey on behalf of Comverge, Inc. at FERC Technical Conference in the Matter of *PJM Interconnection, L.L.C.*, Docket No. ER11-3322-000, July 29, 2011, discussing the topic of appropriate methodologies to estimate load reductions during a demand response curtailment event.

Prepared Direct Testimony of Frank Lacey on behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Commonwealth Edison Company Petition for Statutory Approval of Smart Grid Advanced Metering Infrastructure Deployment Plan Pursuant to Section 16-108.6 of the Public Utilities Act*, Docket No. 12-0298, March 11, 2012.

Oral Cross-examination Testimony of Frank Lacey on behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Commonwealth Edison Company Petition for Statutory Approval of Smart Grid Advanced Metering Infrastructure*

Deployment Plan Pursuant to Section 16-108.6 of the Public Utilities Act, Docket No. 12-0298, May 23, 2012.

Prepared Direct Testimony of Frank Lacey On Behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Ameren Illinois Company Petition for Statutory Approval of a Smart Grid Advanced Metering Infrastructure Deployment Plan Pursuant to Section 16-108.6 of the Public Utilities Act*, Docket No. 12-0244 on rehearing, August 24, 2012.

Oral Cross-examination Testimony of Frank Lacey On Behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Ameren Illinois Company Petition for Statutory Approval of a Smart Grid Advanced Metering Infrastructure Deployment Plan Pursuant to Section 16-108.6 of the Public Utilities Act*, Docket No. 12-0244 on rehearing, September 20, 2012.

Prepared Direct Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Commonwealth Edison Company's Petition for Approval of Tariffs Implementing ComEd's Proposed Peak Time Rebate Program*, Docket No. 12-0484, October 25, 2012.

Oral Cross-examination Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Commonwealth Edison Company's Petition for Approval of Tariffs Implementing ComEd's Proposed Peak Time Rebate Program*, Docket No. 12-0484, December 7, 2012.

Prepared Direct Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Maryland Public Service Commission in the matter of *The Investigation of the Process and Criteria for Use in Development of Requests for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149, January 31, 2013.

Prepared Supplemental Direct Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Maryland Public Service Commission in the matter of *The Investigation of the Process and Criteria for Use in Development of Requests for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149, February 25, 2013.

Oral Testimony of Frank Lacey on behalf of Comverge, Inc. at FERC Technical Conference in the Matter of *PJM Interconnection, L.L.C.*, Docket No. ER13-2108-000, October 11, 2013, discussing the appropriate information requirements for demand response offers made three years prior to a delivery year.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy before the Massachusetts Department of Public Utilities in the *Investigation as to the Propriety of Proposed Tariff Change* in response to the Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, Docket Number DPU 15-155, March 18, 2016.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy before the Massachusetts Department of Public Utilities in the *Investigation as to the Propriety of Proposed Tariff Change* in response to the Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, Docket Number DPU 15-155, April 28, 2016.

Oral Cross-examination Testimony of Frank Lacey on behalf of Direct Energy before the Massachusetts Department of Public Utilities in the *Investigation as to the Propriety of Proposed Tariff Change* in response to the Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, Docket Number DPU 15-155, May 18, 2016.

Expert Rebuttal Report and Damage Summary of Frank Lacey, Response to the Review Submitted by Nathan Katzenstein, prepared on behalf of Astral Energy in the matter of *Treetop Development, et al. v. Astral Energy, et al.*, Docket #: BER-L-9414-13, Superior Court of New Jersey, Bergen County, December 9, 2016.

Expert Reply (Sur-rebuttal) of Frank Lacey, Reply to the Response Submitted by Nathan Katzenstein, prepared on behalf of Astral Energy in the matter of *Treetop Development, et al. v. Astral Energy, et al.*, Docket #: BER-L-9414-13, Superior Court of New Jersey, Bergen County, April 28, 2017.

Deposition of Frank Lacey on the topic of his Expert Rebuttal Report and Damage Summary prepared on behalf of Astral Energy in the matter of *Treetop Development, et al. v. Astral Energy, et al.*, Docket #: BER-L-9414-13, Superior Court of New Jersey, Bergen County, May 17, 2017.

Oral Testimony and Cross-examination Testimony on behalf of Astral Energy in the matter of *Treetop Development, et al. v. Astral Energy, et al.*, Docket #: BER-L-9414-13, Superior Court of New Jersey, Bergen County, June 5, 2017.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Clearview Energy before the Pennsylvania Public Utilities Commission in *Pennsylvania PUC v. Clearview Electric, Inc.*, Docket No. C-2016-2543592, January 9, 2017.

Prepared Direct Testimony of Frank Lacey on behalf of the Cape Light Compact before the Massachusetts Department of Public Utilities in the *Petition of NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource Energy for*

Approval of their Grid Modernization Plans, Docket No. D.P.U. 15-122/123, March 10, 2017.

Oral Cross-examination Testimony of Frank Lacey (as part of the Cape Light Compact Panel of Witnesses) before the Massachusetts Department of Public Utilities in the *Petition of NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource Energy for Approval of their Grid Modernization Plans*, Docket No. D.P.U. 15-122/123, May 31, 2017.

Prepared Direct Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the Massachusetts Department of Public Utilities in the *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. C. 164, § 94 and 220 C.M.R. § 5.00*, Docket No. D.P.U. 17-05, April 28, 2017.

Oral Cross-examination Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the Massachusetts Department of Public Utilities in the *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. C. 164, § 94 and 220 C.M.R. § 5.00*, Docket No. D.P.U. 17-05, June 27, 2017.

Direct Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the New York Public Service Commission in the *Matter of Eligibility Criteria for Energy Service Companies*, Case No. 15-M-0127, in the *Proceeding on the Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State*, Case No. 12-M-0476, and in the *Matter of Retail Access Business Rules*, Case No. 98-M-1343, September 15, 2017.

Rebuttal Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the New York Public Service Commission in the *Matter of Eligibility Criteria for Energy Service Companies*, Case No. 15-M-0127, in the *Proceeding on the Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State*, Case No. 12-M-0476, and in the *Matter of Retail Access Business Rules*, Case No. 98-M-1343, October 27, 2017.

Oral Cross-examination Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the New York Public Service Commission in the *Matter of Eligibility Criteria for Energy Service Companies*, Case No. 15-M-0127, in the *Proceeding on the Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State*, Case No. 12-M-0476, and in the *Matter of Retail Access Business Rules*, Case No. 98-M-1343, September 15, 2017.

Direct Testimony of Frank Lacey on behalf of Direct Energy Services and its Affiliates before the Virginia State Commerce Commission in the *Application of Virginia Electric and Power Company for Approval of 100% Renewable Energy Tariffs Pursuant to Subsection 56-577 A 5 and 56-234 of the Code of Virginia*, Docket No. PUR-2017-00060, August 23, 2017.

Oral Surrebuttal and Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services and its Affiliates before the Virginia State Commerce Commission in the *Application of Virginia Electric and Power Company for Approval of 100% Renewable Energy Tariffs Pursuant to Subsection 56-577 A 5 and 56-234 of the Code of Virginia*, Docket No. PUR-2017-00060, December 4, 2017.

Oral Direct and Cross-examination Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the Public Service Commission of the State of Delaware, *In the Matter of the Review of Customer Choice in the State of Delaware*, Docket No. 15-1693, April 19, 2017.

Lacey, Frank, *FERC Order No. 745 – Problems and Solutions to the "EPSA" Problem*, Presentation to National Regulatory Conference, Williamsburg, VA, May 21, 2015.

Panel Discussion, *The State of Demand Response in Organized Markets – The uncertainty created by EPSA v. FERC*, Energy Bar Association, Northeast Chapter Annual Meeting, Newark, NJ, June 11, 2015.

Lacey, Frank, *The Supreme Court on Energy in 2016, What it Means to Your Business, Presentation to Solar Power International, Las Vegas, NV, September 14, 2016.*

Lacey, Frank, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Presentation to Solar Power International, Las Vegas, NV, September 11, 2017.

Lacey, Frank, *Update: Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators* Solar Power Northeast, February 5, 2018.

Lacey, Frank, *"The Extermination of BUGS from the US Electricity Markets"*, *em – The Magazine for Environmental Managers*, published by the Air and Waste Management Association, March 2016.

Webinar Participant/Panelist, *The Future of Demand Response*, hosted by Power Markets Today, October 17, 2017.

Webinar Participant/Panelist, *Rethinking Demand Response – The Evolution from Simple to Sophisticated*, Hosted by Smart Electric Power Alliance, December 14, 2017.

Lacey, Frank and Taff Tschamler, *Implementing Principles of Default Service: A Roadmap for Competitive Retail Power Markets*. Paper released at PA POLR Roundtable, May 2004.

Building a for-profit Transmission Operation; Key Business Parameters. Presentation to the EEI Transmission Planning Task Force, Kansas City, MO.

Dozens of industry and client-specific presentations on the topics of industry transformation in the areas of transmission restructuring, retail restructuring, demand response, and the industry ramifications of FERC Order 745 and FERC jurisdiction over demand response.