COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

CASE NO. 2012-00222

APPLICATION OF
LOUISVILLE GAS AND ELECTRIC COMPANY
FOR AN ADJUSTMENT OF ITS ELECTRIC RATES

DIRECT TESTIMONY OF
DENNIS W. GOINS
ON BEHALF OF KENTUCKY INDUSTRIAL
UTILITY CUSTOMERS, INC.

October 3, 2012

TABLE OF CONTENTS

Page

INTRODUCTION AND QUALIFICATIONS 1

CONCLUSIONS 4

RECOMMENDATIONS 5

BACKGROUND 6

LG&E'S PROPOSED CHANGES TO RIDERS CSR10 AND CSR30 11

EXHIBIT

APPENDIX

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INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. Following graduate school I worked as a staff economist at the North Carolina Utilities Commission (NCUC). During my tenure at the NCUC, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the NCUC I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since leaving the NCUC, I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, policy, planning, and pricing issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing issues; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have submitted testimony and affidavits and provided technical assistance in nearly 200 proceedings before state and federal agencies as an expert in competitive market issues, regulatory policy, utility planning and operating practices, cost of service, and rate design. These agencies include the Federal Energy Regulatory Commission (FERC), the Government Accountability Office, state courts in Iowa, Montana, and West Virginia, and regulatory agencies in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Wyoming, and the District of Columbia. Additional details of my educational and professional background are presented in the Appendix.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Kentucky Industrial Utility Customers, Inc. (KIUC). Two KIUC members are served by Louisville Gas & Electric Company (LG&E) under its curtailable service riders—one under Rider CSR10 and the other under Rider CSR30.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review LG&E's proposed revisions to its curtailable/interruptible service.[1]
2. Evaluate the reasonableness of LG&E's curtailable service rate proposals, and recommend necessary changes.

Q. WHAT INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed LG&E's filing, testimony, exhibits, and responses to requests for information.[2] I also reviewed testimony and Commission orders in prior LG&E rate and integrated resource planning (IRP) cases. Finally, I reviewed information found on web sites operated by LG&E's parent company—LG&E and KU Energy LLC., PPL Corporation, PJM—a regional transmission organization, FERC, and the Commission.

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[1] LG&E uses *curtailable* in designating its current and proposed nonfirm rate options for large commercial and industrial customers. Curtailable or interruptible load is generally associated with a customer's agreement either to reduce load to zero or no more than the customer's firm contract demand, or to provide a contractually stated reduction in demand when requested by the host utility. In my testimony, I use *curtailable* and *interruptible* interchangeably except when referring to specific LG&E nonfirm rate options that are designated *curtailable*.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. LG&E currently offers two curtailable rate options—CSR10 and CSR30—under which customers receive an administratively set credit for their curtailable load measured during specified periods.[3] The CSR riders are differentiated by the length of notice a customer receives before a curtailment begins (10 or 30 minutes), maximum annual hours of physical and economic buy-through curtailment permitted,[4] and level of the interruptible demand charge credit. In addition, a CSR customer may choose either of two types of load reduction (Option A or Option B).

2. In this case, LG&E has proposed two significant changes to the CSR riders that unreasonably increase the cost of interruptible service to large manufacturers that have invested millions of dollars in production processes designed to operate efficiently using nonfirm electric service. First, LG&E has proposed reducing the current CSR10 and CSR30 credits by approximately half—a major change that LG&E did not review in advance with current interruptible customers. Second, LG&E has asked the Commission to eliminate the current CSR restriction that limits physical curtailments to system reliability events as defined in the riders. Eliminating this restriction could dramatically increase forced production shutdowns by CSR customers (and associated

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[2] Selected responses related to LG&E's curtailable rates are presented in Exhibit DWG-1.

[3] LG&E's affiliated operating company—Kentucky Utilities Company (KU)—offers the same curtailable rate options.

[4] During a physical curtailment, a CSR customer must reduce load and does not have the option to buy curtailable energy during the curtailment. During an economic curtailment, a CSR customer may either buy curtailable energy at the Automatic Buy-Through Price—a formula-based price specified in the CSR riders, or reduce load either to or below the customer's firm contract demand (Option A) or by a specified amount (Option B).

lost product revenue and profit) in response to physical curtailments that have nothing to do with LG&E's system reliability or ability to serve firm load.[5]

3. LG&E's existing CSR credits are in line with what it and KU spend annually (around $50-$65 dollars per first-year kW)[6] to lower peak demand through its Residential Load Management Program. LG&E does not explain why it wants to reduce the CSR credits by half while leaving the Residential Load Management and other DSM program expenditures intact.
4. LG&E's proposed reduction in the CSR credits—combined with its proposed increases in applicable firm service rates used in conjunction with the CSR riders—dramatically increases the cost of interruptible service relative to firm service. As a result, current and potential CSR customers will have less incentive to buy nonfirm service instead of firm service. This outcome is at odds with LG&E's ongoing load management programs, and could increase LG&E's need for additional generating capacity in the future.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Reject LG&E's proposed changes to curtailable riders CSR10 and CSR30. LG&E has provided no compelling evidence that its

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[5] As I discuss later, LG&E could request a physical curtailment to make an off-system sale. If the CSR physical curtailment restriction is removed, LG&E's test-year cost-of-service should be adjusted in this case to reflect margins from potential incremental off-system sales related to CSR physical curtailments. Otherwise, LG&E would be able to retain these profits until its rates were adjusted in its next rate case.

[6] This annual amount is equivalent to about $4-$5 per kW-month.

current interruptible service for large customers is either under-priced or inordinately inflexible. LG&E's proposed changes do not reflect its cost of providing interruptible service, arbitrarily reduce by half credits that were set just two years ago, dramatically decrease the attractiveness of interruptible service to new customers, and could result in current interruptible load leaving the LG&E system.

2. Increase the current CSR credits marginally (by about 3 percent) to maintain approximately the current relative price relationship between LG&E's firm and nonfirm service. I present details of these increased CSR credits later in my testimony.

BACKGROUND

Q. WHAT IS INTERRUPTIBLE SERVICE?

A. Interruptible or curtailable service is a separately identifiable nonfirm utility product that allows a supplier to interrupt or curtail customer loads—usually when reliability to firm service customers is impaired or endangered. In general, interruptible load enables a supplier to maximize the value of existing capacity resources and to avoid acquiring new capacity resources. In addition, utilities can also use interruptible load, if permitted, to enable high-value off-system sales or to mitigate high incremental fuel costs borne by firm service customers.

On a daily basis, utilities serve interruptible loads using available generating resources that are not required to serve firm load. That is, the available supply of interruptible service depends on the relationship between available power supply resources and firm service demands at a point in time. If firm load uses all available power supply resources in a particular hour, the supply of interruptible service falls to zero—that is, interruptible loads are interrupted. When firm load is less than available resources, interruptible service is available.

Q. ARE INTERRUPTIBLE SERVICE AND RATE OPTIONS COMMON IN THE ELECTRIC UTILITY INDUSTRY?

A. Yes. Interruptible service is and has been a common service offered by most electric utilities. Federal legislation passed in 1978[7] recognized the value of interruptible rates and required state regulatory commissions to consider adopting them. Current federal policy continues to support such rates and other demand response mechanisms. A 2006 report by the Brattle Group on behalf of the Edison Electric Institute described interruptible service as follows:

> Utilities traditionally have offered large commercial and industrial customers such credits through interruptible service tariffs. Under such tariffs, customers typically receive a credit in return for agreeing to curtail all or a significant portion of their load up to several times a year, at times when the utility has a system operating emergency or when incremental generating costs are very high. Although enrollment in these programs usually is voluntary, the participant can face significant financial penalties if it fails to reduce demand when directed to do so, such as paying the spot market price for electricity consumed during a requested interruption period. Curtailable demand provides the utility or system operator with another resource to maintain system stability when resources are tight and also can reduce a utility's installed capacity obligations.[8]

Q. DOES INTERRUPTIBLE LOAD PROVIDE TANGIBLE CAPACITY, OPERATING, AND ECONOMIC BENEFITS?

A. Yes. Interruptible load can and should be a significant element of any electric utility's demand-response efforts. Interruptible load has long been

[7] Public Utility Regulatory Policies Act of 1978 (PURPA).

recognized as a means to avoid the cost of adding generating and transmission capacity. It provides operating reliability benefits by substituting, in certain cases, for such ancillary services as spinning and operating reserves. Interruptible load expands the range of resources available to meet contingencies, lowers customer costs, and can even be used to mitigate wholesale price volatility and curb potential market power problems. Interruptible service is also a form of insurance or safety net, protecting against emergency situations if and when they occur. In addition, interruptible load can create environmental benefits by avoiding the impacts of constructing and operating fossil generation.

Interruptible load also helps states to promote economic development and manufacturing jobs retention. The availability of an effective interruptible service option is often a key factor in determining where a manufacturing facility is located, particularly if the manufacturing process is energy intensive. In addition, the continuing long-term availability of cost-effective interruptible rate options can help keep established manufacturers competitive and growing.

Q. IN YOUR OPINION, WHY DO LARGE MANUFACTURERS GENERALLY TAKE INTERRUPTIBLE SERVICE?

A. Manufacturers with flexible production processes involving electricity-intensive equipment—for example, kilns and arc furnaces—often find it economically essential to use nonfirm electric service to control production costs and maintain or improve their competitive position in national and global markets. Such manufacturers do not require firm service to make their products. Instead, they need reasonable and fairly priced interruptible rate options that provide mutual benefits to them, their host utility, and firm service customers.

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[8] Frank Graves, et. al., *PURPA: Making the Sequel Better than the Original* (EEI, December 2006) at 35.

Q. HOW SHOULD INTERRUPTIBLE SERVICE BE PRICED?

A. Interruptible service should be priced to reflect the supplier's reduced cost of providing nonfirm, interruptible service. This is generally done through either lower stand-alone interruptible rates, or through credits or discounts to firm service rates that reflect avoided cost savings and reduced costs of service. For example, regarding how avoided cost principles can be used in setting interruptible credits, the EEI report I noted earlier states:

> At a high level, one first needs to determine the types of costs that a utility could avoid as a result of customer demand reductions. Peak load reductions enable a utility to avoid serving a portion of its load at times when marginal energy prices are high, so they clearly enable the utility to avoid energy costs (i.e., fuel and other variable production costs). Moreover, peak load reductions that a utility can count on in a planning sense could enable a utility to avoid building or purchasing peak generating capacity, which suggests that the ***credits could reflect the capacity cost of peaking units, such as combustion turbines***.[9]

Q. SHOULD AN INTERRUPTIBLE RATE RECOVER ANY FIXED PRODUCTION COSTS?

A. No. From a pricing standpoint, interruptible rates—although they provide demand response benefits—should not be viewed as an incentive program similar to typical energy efficiency and demand-side management programs. Instead, interruptible rates should reflect basic cost principles. Fundamental economic theory demonstrates that interruptible customers do not cause the utility to incur production capacity costs. For example, Professor James C. Bonbright, a recognized pricing authority, advocated pricing interruptible service to reflect no capacity-related cost of service:

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[9] *Id.* at 35 (internal citations omitted, emphasis added).

> Interruptible service has been used by both gas and electric companies for peak shaving. The costs cannot be accurately determined because it is a byproduct resulting from generating and bulk transmission facilities built and operated for firm service (see Nissel, 1983). As a result, only the customer cost (e.g., customer-connected spur lines and substations) and energy costs (e.g., fuel and incremental maintenance cost) actually incurred and ***no capacity pricing cost should be included in pricing interruptible service***.
>
> While some feel that it is an impropriety to treat interruptible customers as if they were firm customers, they still opine that it would be fair and reasonable to obtain a small contribution from them for capacity costs. This is debatable.[10]

Q. ARE INTERRUPTIBLE CUSTOMERS "FREE RIDERS" IF THEY PAY NO DEMAND-RELATED PRODUCTION COSTS?

A. No. Under an efficient pricing scheme, customers should only pay for costs attributable to their demands. Since a utility is not required to build or acquire generating capacity to serve interruptible load, only firm service customers should pay for the demand-related costs of this capacity. If interruptible rates recover part of the fixed costs of capacity built to serve only firm loads, then interruptible customers cannot be "free riders."

Q. HOW CAN THE CAPACITY VALUE OF INTERRUPTIBLE LOAD BE EVALUATED?

A. In evaluating the capacity value of interruptible load, the long-term avoided cost of peaking generation capacity is often the starting point. Interruptible load helps suppliers avoid not only peaking capacity costs, but also the cost of reserve capacity that would have been required if the interruptible load was firm, as well as the cost of transmission losses. As a

[10] James C. Bonbright, *et al.*, *Principles of Public Utility Rates*, (Arlington, Virginia: Public Utilities Reports, Inc., 1988), at 502 (emphasis added).

result, an interruptible capacity credit should be adjusted (increased) to reflect the avoided cost of reserves and losses.

Q. DOES INTERRUPTIBLE SERVICE PROVIDE OTHER BENEFITS?

A. Yes. In addition to avoiding generation capacity costs, interruptible load can be used to:

- Promote economic development and manufacturing jobs retention. As I noted earlier, competitive rate options are often key factors in decisions by electricity-intensive manufacturers to locate production facilities. Cost-based interruptible service helps attract and retain large, energy-intensive industrial customers that provide jobs and tax revenues—a fact that should not be forgotten in structuring LG&E's interruptible program.
- Avoid bulk transmission costs.
- Avoid high marginal energy costs.
- Avoid environmental costs associated with constructing and operating production and bulk transmission facilities.

LG&E'S PROPOSED CHANGES TO RIDERS CSR10 AND CSR30

Q. PLEASE DESCRIBE LG&E'S CURRENT CURTAILABLE RATES.

A. LG&E currently offers two stand-alone curtailable options—Riders CSR10 and CSR30. These riders are differentiated by:

- Advance curtailment notice (10 minutes for CSR10 and 30 minutes for CSR30).
- Maximum annual hours of physical and economic buy-through curtailment permitted. Under the CSR riders, LG&E may curtail service up to 375 hours (CSR10) or 350 hours (CSR30) annually.

Physical curtailments are limited to 100 hours annually under each CSR rider.

- Level of interruptible demand charge credit ($5.40-$5.50 per kW-month for CSR10 and $4.30-$4.40 per kW-month for CSR30).

In addition, a CSR customer must choose between two types of load reductions it will provide in response to a curtailment request from LG&E. Under Option A, a CSR customer agrees to reduce load when requested to the contract level of firm demand. Under Option B, the customer must reduce load by a predetermined amount (Designated Curtailable Load). LG&E and KU currently serve 5 customers under their large customer interruptible rate program. See Table 1 below.

Table 1. KU/LG&E: Current CSR Rates

Item	CSR10	CSR30
Notice (minutes)	10	30
Curtailment Hours		
Physical	100	100
Buy-Through	275	250
Total	375	350
Credit ($/kW-mo)		
Primary	5.50	4.40
Transmission	5.40	4.30
Customers		
KU	3	0
LG&E	1	1

Q. HAS LG&E PROPOSED MAJOR CHANGES TO ITS CURTAILABLE SERVICE OPTIONS?

A. Yes. In this case, LG&E has proposed two major changes to the CSR riders:

- Reducing the CSR credits by nearly 50 percent. (See Table 2 below.) LG&E's proposed credit reductions will increase the cost of interruptible service to large manufacturers by nearly $0.7

million annually.[11] This increase is in addition to LG&E's proposed increase in the applicable firm service rates for CSR customers.

Table 2. KU/LG&E: Proposed CSR Credits

	Credit ($/kW-mo)		
	Pres	Prop	Chng
CSR10			
Primary	5.50	2.80	-49%
Transmission	5.40	2.75	-49%
CSR30			
Primary	4.40	2.30	-48%
Transmission	4.30	2.25	-48%

Proposed CSR credits = $/kVA-mo. Credits shown above assume PF=1, where PF is Power Factor.

- Eliminating the current CSR restriction that limits physical interruptions to system reliability events as defined in the riders. That is, LG&E wants the right to call physical interruptions for any reason for up to 100 hours each year.

Q. DID LG&E CONSULT CURRENT CURTAILABLE CUSTOMERS BEFORE DECIDING ON THE CHANGES PROPOSED IN RIDER CSR?

A. No.[12]

Q. HOW DID LG&E JUSTIFY ITS PROPOSED REDUCTION IN THE CSR CREDITS?

A. LG&E witness Lonnie E. Bellar stated:

> Although the ***credits LG&E currently provides*** under its CSRs ***are less then the estimated cost of a combustion turbine*** ("CT") in today's marketplace, they are still too high in view of

[11] Robert Conroy, direct testimony at Conroy Exhibit R4, page 3.
[12] *See* LG&E's response to KIUC data request 1-44.c and KPSC data request 2-83.a in this case.

> the significant limitations on the use of CSR and the availability of only 100 hours of physical interruption.[13]
>
> The result of changing the CSRs as LG&E proposes will be to bring the amount of the CSR credits more in line with the actual ***economic value CSR customers provide***. This approach should still provide CSR customers with a healthy incentive to participate in the program while ensuring non-CSR customers receive a ***fair value*** for the credits they provide.[14]

In other words, LG&E appears to want to price CSR interruptible on the basis of *value of service* instead of *cost of service.*

Q. IN THIS CASE, HAS LG&E EQUATED VALUE OF SERVICE WITH COST OF SERVICE IN DISCUSSING CSR CREDITS?

A. Yes. In response to a KIUC data request regarding how CSR credits should be set, LG&E responded:

> CSR pricing should generally reflect ***cost of service principles***. More specifically, CSR pricing should generally reflect the ***avoided cost*** associated with being able to curtail CSR load in a timely manner.[15]

However, in response to another KIUC data request in which it elaborated on this statement, LG&E said:

> With respect to CSR service, ***value-of-service*** corresponds to the ***avoided cost*** of being able to curtail CSR load; therefore, value-of-service is equivalent to cost of service.[16]

Q. IS VALUE OF SERVICE AN APPROPRIATE BASIS FOR PRICING LG&E'S INTERRUPTIBLE SERVICE?

A. No. Value-of-service pricing typically reflects charging what the market will bear for a product—that is, a form of monopoly pricing involving

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[13] Lonnie E. Bellar, direct testimony at 20:19-21:2 (emphasis added).
[14] *Id.* at 22:16-22 (emphasis added).
[15] *See* LG&E's response to KIUC data request 1-64(e). (Emphasis added.)
[16] *See* LG&E's response to KIUC data request 1-64(f). (Emphasis added.)

price discrimination. I have been informed by counsel that in Kentucky, electricity rates are supposed to be based on cost of service—not value of service. As I noted earlier, nonfirm service is an identifiable product that a utility can sell in addition to firm service simply because all of its supply resources are not needed at all times to serve firm load. In the case of a regulated monopoly utility that supplies both firm and nonfirm services to captive customers, pricing firm service on the basis of cost of service while pricing nonfirm service on the basis of value of service would be discriminatory, unjust, and unreasonable.

Q. IS LG&E CORRECT THAT CSR CREDITS SHOULD BE MARKEDLY LESS THAN THE FULLY LOADED COST OF A CT THAT OPERATES MORE HOURS THAN ARE AVAILABLE FOR INTERRUPTION UNDER THE CSR RIDERS?

A. No. In making this argument, witness Bellar[17] ignored the fundamental concept underlying interruptible or nonfirm service. That is, interruptible service is available only when available supply resources exceed a utility's firm load. I have been unable to identify any evidence LG&E has provided that supports the notion that the current 350-375 hour limit on CSR interruptions impedes LG&E's ability to supply firm service, causes LG&E to add additional generating capacity, or unduly restricts LG&E's ability to operate safely and efficiently.

Witness Bellar's also seems to confuse the nonfirm CSR product that LG&E sells with the CT generating capacity that it builds or buys. They are not the same. If LG&E avoids building or buying capacity because it serves interruptible load, then the standalone price for this nonfirm service should reflect only variable operating costs and exclude all production capacity charges. LG&E has chosen not to price CSR interruptible service this way. Instead, LG&E links the nonfirm CSR price to an otherwise applicable firm service rate using a credit against the demand charge(s) in the firm rate. The appropriate CSR credit in this case is one that approaches the annualized cost of peaking (CT) capacity, adjusted upward for reserves.

Q. DID LG&E CITE EXAMPLES OF CURRENT LOW MARKET PRICES FOR CT AND DEMAND RESPONSE CAPACITY AS JUSTIFICATION FOR LOWERING THE CSR CREDITS?

A. Yes. LG&E cited several examples of current market prices for CT and demand response capacity that are below existing CSR credits.[18] For example, LG&E indicated that the purchase price that it recently negotiated for the Bluegrass CTs equivalent to $1.85 per kW-month. LG&E also noted that PJM's base residual auction for the 2015-15 delivery year yielded an implied market price for demand response resources of $3.83 per kW-month. LG&E argues that these capacity market prices support lowering the CSR10 credits to $2.75 per kVA-month for transmission delivery customers and $2.80 per kVA-month for primary delivery customers.

Q. HAS LG&E COMPLETED THE BLUEGRASS PURCHASE?

A. No. In June 2012, LG&E and KU notified the Commission that they were terminating their pending purchase of the Bluegrass CTs.

Q. IS LG&E A MEMBER OF PJM OR ANY OTHER RTO?

A. No. LG&E does not participate in PJM's capacity auctions, and cannot buy or sell demand response resources in PJM's capacity markets.

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[17] *Id.* at 21:3-15.
[18] *Id.* at 21:16-22:4.

Q. SHOULD AN INTERRUPTIBLE CREDIT BE BASED ON SUCH SHORT-TERM MARKET MEASURES OF CAPACITY AS THE ANNUAL COST OF CAPACITY BID IN PJM MARKETS OR AVAILABLE TO LG&E IN WHOLESALE MARKETS?

A. No. Short-run market prices fluctuate to reflect current market conditions for existing generating capacity, while long-run avoided costs reflect the cost of adding new capacity to meet demand growth. Long-run—not short-run—capacity costs more accurately reflect avoided cost savings attributable to interruptible service. Short-run prices do not give a clear signal regarding the cost of capacity to serve future peak demands. In addition, basing an interruptible credit on short-run market capacity prices is similar to relying solely on spot market purchases to meet future energy needs—both approaches increase consumer risks via unstable and unpredictable prices. Moreover, interruptible rates that reflect short-term price fluctuations may impede the development of robust and effective retail interruptible programs. In my opinion, a key to developing a stable and effective interruptible program is to rely on curtailable credits that reflect the long-run avoided cost of adding capacity—not a short-term value that reflects current capacity surpluses or shortages.

Setting administratively determined curtailable credits to reflect short-run market conditions is a short-sighted and improper approach that ignores the long-term commitment (either contractual or operational) reflected in the demand for interruptible service by many large, electricity-intensive customers. Moreover, a short-run focus in setting these credits is akin to asking a utility to base its test-year revenue requirement to reflect current market conditions instead of costs incurred to make long-lived investments in generation, transmission, and distribution plant and equipment. A utility might like that option when capacity is constrained and prices are high, but would abhor it when excess capacity drives market prices down temporarily.

Q. WHEN THE COMMISSION APPROVED THE STIPULATION IN THE 2010 RATE CASE SETTING THE CURRENT CSR CREDITS, WAS INFORMATION AVAILABLE ABOUT NEAR-TERM DEMAND RESPONSE CAPACITY PRICES IN PJM?

A. Yes. By June 2010 when the Commission issued an order approving the stipulation, LG&E had available the results from PJM's capacity auctions for the 2012-13 and 2013-14 delivery years. That is, LG&E knew or should have known that near-term prices in PJM's capacity markets were below the CSR credits to which it was agreeing, and which the Commission approved as just and reasonable. In the current case, LG&E is trying to revise dramatically what the Commission established just two years ago.

Q. DOES LG&E HAVE MORE HOURS OF INTERRUPTION AVAILABLE UNDER ITS CSR PROGRAM THAN PJM DOES WITH ITS CURRENTLY LOW-PRICED DEMAND RESPONSE CAPACITY?

A. Yes. LG&E has between 350-375 hours of CSR interruptions available, of which 100 hours reflect physical interruptions. Under PJM's demand response programs, a customer receiving the currently low demand response price is only subject to a maximum of 60 hours of physical interruptions each year during June-September. In addition, a PJM demand response customer currently gets at least 2 hours of advance notice before an interruption.

Q. DID ANY KIUC MEMBER SERVED UNDER RIDER CSR MAKE A MAJOR PRODUCTION INVESTMENT IN PART ON THE BASIS OF CSR CREDITS APPROVED IN THE 2010 RATE CASE?

A. Yes. As explained in the testimony of KIUC witness John Gant, Carbide Industries—an LG&E customer—decided to rebuild an electric arc furnace in 2011 in part because of the CSR credits that were approved in the 2010 rate case. To lower the credits by half as proposed by LG&E would be pulling the proverbial rug from under a long-time customer that invested millions of dollars and preserved hundreds of jobs in part because of the current CSR credits.

Q. REGARDING LG&E'S PROPOSAL TO ELIMINATE THE RESTRICTION ON PHYSICAL CURTAILMENTS, DID LG&E IDENTIFY CONDITIONS OTHER THAN A SYSTEM RELIABILITY EVENT UNDER WHICH IT MIGHT WANT TO CALL A PHYSICAL CURTAILMENT?

A. Yes. LG&E identified one situation other than a system reliability event in which it might want to call a physical curtailment—namely, "anytime the economic benefit of curtailment would be greater than the marginal cost of production utilizing another resource...."[19] LG&E's response implies that if allowed, it would call a physical curtailment whenever the incremental revenue from continuing an interruptible sale to a CSR customer was less than the marginal cost of the capacity resource supplying the sale. But the situation described by LG&E seems to be one requiring an economic buy-through curtailment—not a physical curtailment. I am unaware of any evidence LG&E has provided in this case showing that this issue could not be handled within the 250-275 hours of economic curtailments it is permitted under the existing CSR riders.

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[19] *See* LG&E's response to KIUC data request 1-54 and KPSC data request 2-83.c.

A second situation exists that was not mentioned by LG&E. Specifically, in response to a data request, LG&E acknowledged that eliminating the restriction on physical curtailments would allow it to interrupt CSR service to make a higher value off-system sale.[20] LG&E's response implied that non-CSR customers would get the benefit of such incremental off-system revenue. However, non-CSR customers would get no incremental benefit unless the additional off-system sales revenue was captured in a test-year adjustment used to set LG&E's base rates. Otherwise, LG&E's shareholders would be the beneficiary of incremental margins from off-system sales resulting from eliminating the physical curtailment restriction in the CSR riders. I reviewed LG&E's test-year cost-of-service adjustments in this case, and found no adjustment to reflect potential incremental margins from CSR physical-curtailment-related off-system sales. As a result, unless LG&E's test-year cost of service is adjusted in this case, the earliest that potential physical-curtailment-related margins could be captured for non-CSR customers would be when LG&E's rates are adjusted in its next rate case.

Q. COULD THIS INCREMENTAL OFF-SYSTEM SALES MARGIN IMPACT BE SIGNIFICANT?

A. Yes. Assume that as a result of eliminating the CSR physical curtailment restriction, LG&E (combined with KU) could sell an additional 11,250 MWh of off-system firm energy by physically curtailing 150 MW of CSR load during 75 hours of non-reliability physical curtailments (150 MW x 75 hr. = 11,250 MWh). Assume the average incremental margin of these off-system sales is $100 per MWh. In this example, eliminating the current CSR limit on physical curtailments without reflecting potential incremental off-system earnings in rates set in this case could allow LG&E and KU to earn and retain for shareholders an additional $1.1 million in

[20] *See* LG&E's response to KIUC data request 2-119.

profit annually—at least until next base rate adjustment. The potential to retain incremental off-system sales margins may help to explain LG&E's request to eliminate the current CSR restriction on physical curtailments.

Q. DID LG&E IDENTIFY ANY SITUATION IN WHICH THE EXISTING 100-HOUR LIMIT ON PHYSICAL CURTAILMENTS HAS IMPEDED ITS ABILITY TO OPERATE RELIABLY AND SERVE FIRM CUSTOMERS?

A. No.

Q. ARE THE CURRENT CSR CREDITS OUT OF LINE WITH LG&E'S COST OF PEAK LOAD REDUCTION IN SOME OF ITS OTHER LOAD MANAGEMENT PROGRAMS?

A. No. I briefly reviewed some of LG&E's current load management programs, including program analyses and cost information provided to the Commission by LG&E and KU in recent IRP and demand-side management (DSM) cases.[21] None of the programs is directly comparable to the CSR program, but several focus on reducing peak demands. For example, in its Residential Load Management (Demand Conservation) program, LG&E installs switches to control selected residential loads (air conditioners, heat pumps, pool pumps, and water heaters) to reduce peak demand. The estimated annual first-year cost per kW of reduced summer peak demand for LG&E's Residential Demand Conservation program ranges from around \$50-\$65 per kW—or about \$4-\$5 per kW-month.[22] This cost is in line with the existing CSR credits even though the CSR

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[21] For example, Case Nos. 2011-00140 and 2011-00134.

[22] *See* Case No. 2011-00140, *2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Volume 1* at 8-75 and 8-76; *see* also, Case No. 2011-00134, KU/LG&E filing, Volume 1, Exhibit MEH-1 at 19-25, and ICF International, *Louisville Gas and Electric Company/Kentucky Utilities Company: DSM Program Review-Report*, March 18, 2011, at 27. Annual cost estimates for LG&E's Commercial Demand Conservation program are similar to those for the residential program.

program gives LG&E significantly greater load reduction flexibility.[23] For example, service interruptions in the residential program for air conditioning systems are limited to 20 cycling events in the summer months, exclude week-ends and holidays, and typically occur only between 2 pm and 6 pm. In general, I find LG&E's heightened concern about the level of CSR credits surprising given what it spends annually on residential and commercial DSM programs that focus on load control and peak demand reduction.

Q. SHOULD THE CSR CREDITS BE REDUCED AS LG&E RECOMMENDS?

A. No. In fact, they should be marginally increased to maintain the relative price relationship between LG&E's firm and nonfirm services. For example, the current ratio of the CSR10 transmission credit ($5.40 per kW-month) to the Retail Transmission Service (RTS) demand charge ($6.69 per kVA-month) is about 0.80. To maintain this relative price relationship under LG&E's proposed RTS rate ($8.10 per kVA-month), the CSR10 transmission credit would have to increase to about $6.50 per kVA-month. Similar relative price ratios could be developed for other applicable large customer rates.

In the interest of rate stability and gradualism, I recommend increasing the CSR credits by about 3 percent. This small increase will keep the price of LG&E's nonfirm service from rising dramatically as it does under LG&E's proposed CSR credits, and help to retain existing CSR customers and attract new ones. Moreover, the increase keeps the CSR credits in line with DSM credits LG&E offers in its Commercial Load Management program. My proposed CSR credits are shown in Table 3 below.

[23] Existing annual credits per controlled appliance under the Residential Demand Conservation program range from $8 (pool pumps and water heaters) to $20 (central air conditioners and heat pumps).

Table 3. KIUC: Proposed CSR Credits

	Credit ($/kW-mo)		
	Pres	**Prop**	**Chng**
CSR10			
Primary	5.50	5.64	3%
Transmission	5.40	5.54	3%
CSR30			
Primary	4.40	4.51	3%
Transmission	4.30	4.41	3%

Proposed CSR credits = $/kVA-mo. Credits shown above assume PF=1, where PF is Power Factor.

Q. SHOULD THE COMMISSION ADOPT YOUR RECOMMENDED CSR CREDITS AND RETAIN THE CURRENT RESTRICTION ON PHYSICAL CURTAILMENTS?

A. Yes. My proposed CSR credits—along with retaining the current restriction on physical curtailments-balance the interests of both LG&E and curtailable customers. In my opinion, adopting LG&E's CSR proposals will impede the development of curtailable load on the LG&E system, reduce long-term benefits to both firm and interruptible customers, and force LG&E to lean more heavily on supply-side resources.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

Commonwealth of Virginia)
County of Fairfax) SS

Before me this day appeared DENNIS W. GOINS of Potomac Management Group, who stated under oath that the foregoing testimony was prepared by him or under his direct supervision and control; that he has knowledge of the matters set forth in said testimony; and that such matters are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to me this 1st day of October 2012.

Dennis W. Goins

Notary Public

My Commission Expires: 4-30-14

BARBARA A. CUPP
Notary Public
Commonwealth of Virginia
179781
My Commission Expires Apr 30, 2014

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

CASE NO. 2012-00222

APPLICATION OF
LOUISVILLE GAS & ELECTRIC COMPANY
FOR AN ADJUSTMENT OF ITS ELECTRIC RATES

EXHIBIT TO THE
DIRECT TESTIMONY OF
DENNIS W. GOINS
ON BEHALF OF KENTUCKY INDUSTRIAL
UTILITY CUSTOMERS, INC.

October 3, 2012

Exhibit DWG-1

LG&E's Responses to Selected Data Requests

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-44

Responding Witness: Lonnie E. Bellar / Counsel

Q1-44. Referring to the proposed Curtailable Service Riders CSR10 and CSR30:

a. Please provide in native format all workpapers, studies, analyses, and documents (all Excel worksheets with working formulas and intact links) supporting and/or underlying the development of the proposed riders.

b. Provide all studies and/or analyses that LG&E conducted concerning expected customer acceptance of and willingness to receive service under the proposed riders.

c. Identify and provide all documents provided to and correspondence with existing and potential interruptible customers related to the development, implementation, and operation of the proposed CSR riders.

d. Identify and provide all alternative rate credits for the CSR riders that LG&E considered but rejected, and describe in detail the reasons for rejecting the considered alternative(s).

A1-44. a. See Attachment 1, which describes load management in PJM, and Attachment 2, which details of combustion turbine availability and utilization. Pricing of the Bluegrass Combustion turbines can be found in Case No. 2011-00375.

b. LG&E did not perform the requested analysis.

c. LG&E did not correspond with existing or potential interruptible customers when developing the proposed CSR riders. See also the response to KPSC 2-83(a).

d. Objection. All decisions regarding which rates, rate design and rate credits to include in the application in this proceeding were made in consultation with legal counsel. Any response to this question necessarily requires the Company to reveal the contents of communications with counsel and the mental impressions of counsel, which information is protected from disclosure by the attorney-client privilege and the work product doctrine. The Commission determined in its July 30, 2010 Order in Case No. 2009-00549 that such information is not discoverable. See pages 7-10 and ordering paragraph 5 of the Commission's Final Order in Case No. 2009-00549 dated July 30, 2010.

Load Management in PJM

Introduction

Load management is a broad term to describe load that responds to PJM emergencies. There are three primary types of load management recognized by PJM:

1. Direct Load Control (DLC)
    a. Programs such as water heater or AC control
2. Firm Service Level (FSL)
    a. Curtailment down to predetermined firm service level
3. Guaranteed Load Drop (GLD)
    a. Curtailment of set amount of load

Demand Resources (DR) is the term PJM uses for load management that participates in the PJM Capacity Market which is called RPM (Reliability Pricing Model). While Demand resources can participate in several PJM markets the bulk of their annual revenues (~95%) are derived from capacity payments in the RPM capacity market. See section below.

Three categories of DR are allowed to be offered in the RPM auctions based on the limitations of curtailment.

Name	# of Activations	Period	Max hours	Hours
Limited	10	Jun-Sep	6	Noon-8pm
Ext Summer	Unlimited	May-Oct	10	10A-10P
Annual DR	Unlimited	All Months	10	10A-10P (sum) 6A-9p (win)

The base RPM auction is conducted annually for a Delivery Year (DY) three years in the future. For example, in the spring of 2012, the auction will be run for the 2015/16 Delivery Year which runs from June 1, 2015 to May 31, 2016. Incremental auctions are conducted during the year leading up to the Delivery Year.

General Requirements

Load management resources must register with PJM via a Curtailment Service Provider (CSP). Financial settlements are between PJM and the CSPs. Settlement between the CSP and the retail customer is a private agreement between them. CSPs must be able to provide customer specific compliance and verification with 45 days of event. Interval metering at the customer site is required for verification. CSP must be able to receive and acknowledge communications with PJM's "ALL CALL" system, which is used to implement "Load Management Event".

DR Revenues in 2011

Following is the revenues received by PJM Demand Resources in 2011.

Capacity	$487,104,180	94.9%
Real-Time Economic	$2,045,338	0.4%
Day-Ahead Economic	$7,658	0.0%
Synchronized Reserves	$9,399,509	1.8%
Emergency Energy	$14,833,294	2.9%
Total	**$513,389,979**	

There was approximately 11,821MW of Demand Resources in 2011, so the average revenue was approximately $43,430/MW-Yr.

RPM Auction Clearing Prices History

The following table shows the RPM auction clearing price for the Base Residual Auction (BRA) for each of the Delivery Years for the PJM "RTO" only. It is worth noting, that there was significant price variances for zones within the PJM market for some years.

Delivery Year	**RTO Clearing Price in the initial BRA ($/MW-day)**
2007/08	$40.80
2008/09	$111.92
2009/10	$102.04
2010/11	$174.29
2011/12	$110.00
2012/13	$16.46
2013/14	$27.73
2014/15	$125.99

RPM Auction 2014/15 DY

The spring of 2011 auction for the 2014/15 DY was the first RPM auction to include the three types of DR products (Limited, Extended, Annual). However, the clearing prices for the three products ended up being virtually identical. The capacity market clearing price for the 2014/15 auction conducted in spring 2011 was $125.99/MW-day or ~$46,000/MW-Yr. The Limited product cleared slightly lower at $125.47/MW-day. There was 14,118MW of DR that cleared the 2014/15 DY capacity auction.

History of "Load Management Events" in PJM

Loads cleared in the PJM capacity market are required to curtail load when called upon by PJM in a Load Management Event. These events can be PJM wide or in specific zones within PJM. Historically, PJM has called relatively few events as shown in the table below.

Delivery Year	# of Events
2002/03	3
2003/04	0
2004/05	0
2005/06	2
2006/07	2
2007/08	1
2008/09	0
2009/10	1
2010/11	7
20011/12	1

Penalties for Non-Performance

Load reductions during the PJM Load Management Events are mandatory and as such, penalties are assessed for non-performance. PJM manuals contain fairly specific calculations are how performance is measured for each type of DR, but appears to be somewhat in state of flux due to recent FERC orders on the topic. The financial penalty is based on the MW of shortfall during the event and the following equation:

Compliance Penalty = Lesser of [1/# of events OR 50%) X weighted Annual Revenue Rate

Where Weighted Revenue Rate = Resource Capacity Payment X 365 days

For example, in the 2014/15 timeframe where the capacity payment is $126/MW-day, the penalty would be $23,000 per MW shortfall if there are only one or two events during the Delivery Year.

Comparison to CSR10

The CSR10 retail tariff of LGE/KU provides a payment of $5.40/kw-mo for customer on the curtailable tariff. The following tables shows the PJM capacity payments from the previous 8 RPM auction converted to $/kw-mo:

Delivery Year	RTO Clearing Price in the initial BRA ($/MW-day)	CSR10 Comparable ($/kw-mo)
2007/08	$40.80	$1.24
2008/09	$111.92	$3.40
2009/10	$102.04	$3.10
2010/11	$174.29	$5.30
2011/12	$110.00	$3.35
2012/13	$16.46	$0.50
2013/14	$27.73	$0.84
2014/15	$125.99	$3.83

Daryn Barker
Market Compliance
February 28, 2012

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-45

Responding Witness: Lonnie E. Bellar

Q1-45. Referring to existing Riders CSR10 and CSR30:

a. For each customer (identified only by reference number) served under one of these riders, identify the applicable rider and the total MW of curtailable/interruptible load under contract.

b. State the number of months in which each customer in subpart (a) above has been continuously served under the existing rider or its predecessor(s).

c. For each customer identified in the subpart (a) above, provide the customer's firm contract demand if served under Option A.

d. For each customer identified in the subpart (a) above, provide the customer's Designated Curtailable Load if served under Option B.

A1-45. a-d. See table below.

Customer	Rider	Contract Load		Months of Service	Firm Contract Demand
#1	CSR10	46.5	MW	more than 120	3.5 MW
#2	CSR30	22.7	MW	more than 120	10.0 MW

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-46

Responding Witness: Lonnie E. Bellar

Q1-46. Referring to existing Riders CSR10 and CSR30 and their predecessors:

a. For each customer (identified only by reference number) served under one of these riders, identify the date, time, and duration of each curtailment called by LG&E in the past 60 months?

b. For each curtailment referenced in the response to subpart (a) above, specify whether the curtailment was a system reliability event or a buy-through event, identify the MW of load curtailment requested, and identify the MW of load that failed to comply with the curtailment request.

c. For each buy-through curtailment identified in the response to subpart (b) above, specify whether the customer bought through the curtailment, the amount of buy-through energy purchased, the price paid for such buy-through energy, and the source (system supply or market) of the buy-through price.

A1-46. a.-c. See attached

Interruptions From 04/01/2007 To 03/31/2012

Company	*Start Date/Time*	*End Date/Time*	*Offer Type*	*Offer Price*	*KW Hrs Taken*	*Offer Accepted*	*Hours*
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Customer #1	05/10/2007 13:00	05/10/2007 21:00	Block Offer	105.00	20000.00	YES	8.00
Customer #1	05/10/2007 13:00	05/10/2007 21:00	Block Offer	105.00	1000.00	YES	8.00
Customer #1	07/06/2007 11:00	07/06/2007 18:00	Block Offer	85.00	1000.00	YES	7.00
Customer #1	07/06/2007 11:00	07/06/2007 18:00	Block Offer	85.00	21000.00	YES	7.00
Customer #1	07/09/2007 10:00	07/09/2007 11:00	Block Offer	125.00	19000.00	YES	1.00
Customer #1	07/09/2007 10:00	07/09/2007 19:00	Block Offer	125.00	1000.00	YES	9.00
Customer #1	07/09/2007 11:00	07/09/2007 19:00	Block Offer	125.00	21000.00	YES	8.00
Customer #1	07/10/2007 10:00	07/10/2007 19:00	Block Offer	112.00	21000.00	YES	9.00
Customer #1	07/10/2007 10:00	07/10/2007 19:00	Block Offer	112.00	1000.00	YES	9.00
Customer #1	07/17/2007 13:00	07/17/2007 19:00	Block Offer	80.00	32000.00	YES	6.00
Customer #1	07/17/2007 13:00	07/17/2007 19:00	Block Offer	80.00	20000.00		6.00
Customer #1	07/19/2007 10:00	07/19/2007 13:00	Block Offer	95.00	20000.00	YES	3.00
Customer #1	07/19/2007 10:00	07/19/2007 17:00	Block Offer	95.00	1000.00	YES	7.00
Customer #1	07/19/2007 13:00	07/19/2007 14:40	Block Offer	95.00	14000.00	YES	1.67
Customer #1	07/19/2007 14:40	07/19/2007 17:00	Block Offer	95.00	20000.00	YES	2.33
Customer #1	08/06/2007 12:20	08/06/2007 17:00	Physical Shutdown	0.00	0.00		4.67
Customer #1	08/06/2007 12:20	08/06/2007 17:00	Physical Shutdown	0.00	0.00		4.67
Customer #1	08/07/2007 12:00	08/07/2007 18:00	Block Offer	142.00	21000.00	YES	6.00
Customer #1	08/07/2007 12:00	08/07/2007 18:00	Block Offer	142.00	1000.00	YES	6.00
Customer #1	08/08/2007 12:00	08/08/2007 18:00	Block Offer	130.00	1000.00	YES	6.00
Customer #1	08/08/2007 12:00	08/08/2007 18:00	Block Offer	130.00	21000.00	YES	6.00
Customer #1	08/09/2007 12:00	08/09/2007 18:00	Block Offer	163.00	0.00	NO	6.00
Customer #1	08/09/2007 12:00	08/09/2007 18:00	Block Offer	163.00	21000.00	YES	6.00
Customer #1	08/10/2007 12:00	08/10/2007 18:00	Block Offer	102.00	0.00	NO	6.00
Customer #1	08/10/2007 12:00	08/10/2007 18:00	Block Offer	102.00	21000.00	YES	6.00
Customer #1	08/13/2007 12:00	08/13/2007 14:00	Block Offer	115.00	1000.00	YES	2.00
Customer #1	08/13/2007 12:00	08/13/2007 18:00	Block Offer	115.00	21000.00	YES	6.00
Customer #1	08/13/2007 14:00	08/13/2007 18:00	Block Offer	115.00	1000.00	YES	4.00
Customer #1	08/14/2007 11:00	08/14/2007 20:00	Block Offer	90.00	0.00	NO	9.00
Customer #1	08/14/2007 11:00	08/14/2007 20:00	Block Offer	90.00	21000.00	YES	9.00
Customer #1	08/15/2007 12:15	08/15/2007 18:20	Physical Shutdown	0.00	0.00		6.08
Customer #1	08/15/2007 12:15	08/15/2007 18:20	Physical Shutdown	0.00	0.00		6.08
Customer #1	08/16/2007 12:00	08/16/2007 18:00	Block Offer	107.00	15000.00	YES	6.00
Customer #1	08/16/2007 12:00	08/16/2007 18:45	Block Offer	107.00	0.00	NO	6.75
Customer #1	08/22/2007 14:00	08/22/2007 15:00	Hourly Offer	110.00	13000.00	YES	1.00
Customer #1	08/22/2007 14:00	08/22/2007 19:00	Block Offer	110.00	0.00	NO	5.00
Customer #1	08/22/2007 15:00	08/22/2007 16:00	Hourly Offer	105.00	14000.00	YES	1.00
Customer #1	08/22/2007 16:00	08/22/2007 17:00	Hourly Offer	102.00	14000.00	YES	1.00
Customer #1	08/22/2007 17:00	08/22/2007 18:00	Hourly Offer	115.00	11000.00	YES	1.00
Customer #1	08/22/2007 18:00	08/22/2007 19:00	Hourly Offer	110.00	11000.00	YES	1.00
Customer #1	08/23/2007 12:00	08/23/2007 20:00	Block Offer	130.00	0.00	NO	8.00
Customer #1	08/23/2007 12:00	08/23/2007 20:00	Block Offer	130.00	14000.00	YES	8.00
Customer #1	08/24/2007 12:00	08/24/2007 18:00	Block Offer	100.00	0.00	NO	6.00
Customer #1	08/24/2007 12:00	08/24/2007 18:00	Block Offer	100.00	18000.00	YES	6.00
Customer #1	10/08/2007 13:40	10/08/2007 14:50	Physical Shutdown	0.00	0.00		1.17
Customer #1	10/08/2007 13:40	10/08/2007 14:50		0.00	0.00		1.17
Customer #1	06/09/2008 12:00	06/09/2008 18:00	Physical Shutdown	0.00	0.00		6.00
Customer #1	06/09/2008 12:00	06/09/2008 18:00	Physical Shutdown	0.00	0.00		6.00
Customer #1	07/29/2008 12:00	07/29/2008 17:00	Block Offer	150.00	20000.00	YES	5.00
Customer #1	07/29/2008 12:00	07/29/2008 17:00	Block Offer	150.00	1000.00	YES	5.00

Interruptions From 04/01/2007 To 03/31/2012

Company (1)	*Start Date/Time* (2)	*End Date/Time* (3)	*Offer Type* (4)	*Offer Price* (5)	*KW Hrs Taken* (6)	*Offer Accepted* (7)	*Hours* (8)
Customer #1	08/01/2008 11:00	08/01/2008 13:00	Block Offer	135.00	20000.00	YES	2.00
Customer #1	08/01/2008 11:00	08/01/2008 13:00	Block Offer	135.00	1000.00	YES	2.00
Customer #1	08/01/2008 13:20	08/01/2008 14:00	Physical Shutdown	0.00	0.00		0.67
Customer #1	08/01/2008 13:20	08/01/2008 14:00	Physical Shutdown	0.00	0.00		0.67
Customer #1	08/01/2008 14:00	08/01/2008 18:00	Block Offer	160.00	20000.00	YES	4.00
Customer #1	08/01/2008 14:00	08/01/2008 18:00	Block Offer	160.00	1000.00	YES	4.00
Customer #1	08/04/2008 12:00	08/04/2008 20:00	Block Offer	115.00	20000.00	YES	8.00
Customer #1	08/04/2008 12:00	08/04/2008 20:00	Block Offer	115.00	1000.00	YES	8.00
Customer #1	08/05/2008 11:00	08/05/2008 19:00	Block Offer	120.00	21000.00	YES	8.00
Customer #1	08/05/2008 11:00	08/05/2008 19:00	Block Offer	120.00	26000.00	YES	8.00
Customer #1	08/06/2008 10:00	08/06/2008 16:00	Block Offer	115.00	16000.00	YES	6.00
Customer #1	08/06/2008 10:00	08/06/2008 16:00	Block Offer	115.00	1000.00	YES	6.00
Customer #1	08/07/2008 10:00	08/07/2008 16:00	Block Offer	119.00	20000.00		6.00
Customer #1	08/07/2008 10:00	08/07/2008 16:00	Block Offer	119.00	1000.00	YES	6.00
Customer #1	08/07/2008 11:00	08/07/2008 16:00	Block Offer	119.00	25000.00	YES	5.00
Customer #1	08/20/2008 12:00	08/20/2008 19:00	Block Offer	78.00	12000.00	YES	7.00
Customer #1	08/20/2008 12:00	08/20/2008 19:00	Block Offer	78.00	26000.00	YES	7.00
Customer #1	08/21/2008 11:00	08/21/2008 18:00	Block Offer	79.50	1000.00	YES	7.00
Customer #1	08/21/2008 11:00	08/21/2008 18:00	Block Offer	79.50	18000.00	YES	7.00
Customer #1	09/02/2008 12:00	09/02/2008 20:00	Block Offer	120.00	20000.00	YES	8.00
Customer #1	09/02/2008 12:00	09/02/2008 20:00	Block Offer	120.00	26000.00	YES	8.00
Customer #1	09/03/2008 12:00	09/03/2008 20:00	Block Offer	92.00	21000.00	YES	8.00
Customer #1	09/03/2008 12:00	09/03/2008 20:00	Block Offer	92.00	1000.00	YES	8.00
Customer #1	01/15/2009 07:00	01/15/2009 21:00	Block Offer	70.00	30000.00	YES	14.00
Customer #1	01/16/2009 07:00	01/16/2009 21:00	Block Offer	70.00	30000.00	YES	14.00
Customer #1	06/02/2009 13:00	06/02/2009 17:00	Block Offer	44.00	20000.00	YES	4.00
Customer #1	06/02/2009 13:00	06/02/2009 17:00	Block Offer	44.00	0.00	NO	4.00
Customer #1	06/17/2009 13:00	06/17/2009 17:00	Block Offer	47.00	29000.00	YES	4.00
Customer #1	06/23/2009 13:00	06/23/2009 17:20	Block Offer	62.00	28000.00	YES	4.33
Customer #1	06/24/2009 13:00	06/24/2009 18:00	Block Offer	68.00	0.00	NO	5.00
Customer #1	06/25/2009 13:00	06/25/2009 18:00	Block Offer	62.00	28000.00	YES	5.00
Customer #1	08/10/2009 13:00	08/10/2009 14:00	Block Offer	52.00	30000.00	YES	1.00
Customer #1	08/10/2009 14:00	08/10/2009 15:00	Physical Shutdown	0.00	0.00		1.00
Customer #1	08/11/2009 11:00	08/11/2009 13:30	Hourly Offer	37.50	30000.00	YES	2.50
Customer #1	08/11/2009 13:30	08/11/2009 16:30	Physical Shutdown	0.00	0.00		3.00
Customer #1	08/12/2009 11:00	08/12/2009 17:00	Block Offer	36.50	30000.00	YES	6.00
Customer #1	08/13/2009 13:00	08/13/2009 14:00	Block Offer	36.00	30000.00	YES	1.00
Customer #1	08/13/2009 14:00	08/13/2009 17:00	Block Offer	44.00	30000.00	YES	3.00
Customer #1	08/17/2009 10:00	08/17/2009 11:00	Block Offer	53.00	0.00	NO	1.00
Customer #1	08/17/2009 11:00	08/17/2009 18:00	Block Offer	53.00	1000.00	YES	7.00
Customer #1	08/26/2009 13:00	08/26/2009 14:00	Physical Shutdown	0.00	0.00		1.00
Customer #1	08/26/2009 14:00	08/26/2009 18:00	Block Offer	40.00	30000.00	YES	4.00
Customer #1	08/27/2009 11:00	08/27/2009 18:00	Block Offer	38.00	30000.00	YES	7.00
Customer #1	08/27/2009 11:00	08/27/2009 18:00	Block Offer	38.00	18000.00	YES	7.00
Customer #1	11/04/2009 07:17	11/04/2009 08:00	Physical Shutdown	0.00	0.00		0.72
Customer #1	12/11/2009 06:45	12/11/2009 09:45	Physical Shutdown	0.00	0.00		3.00
Customer #1	12/11/2009 09:45	12/11/2009 11:00	Block Offer	58.00	28000.00	YES	1.25
Customer #1	12/11/2009 11:00	12/11/2009 12:00	Block Offer	65.00	28000.00	YES	1.00
Customer #1	12/11/2009 12:00	12/11/2009 13:00	Block Offer	65.00	28000.00	YES	1.00
Customer #1	12/11/2009 13:00	12/11/2009 14:00	Block Offer	58.00	28000.00	YES	1.00

Interruptions From 04/01/2007 To 03/31/2012

Company (1)	*Start Date/Time* (2)	*End Date/Time* (3)	*Offer Type* (4)	*Offer Price* (5)	*KW Hrs Taken* (6)	*Offer Accepted* (7)	*Hours* (8)
Customer #1	12/11/2009 14:00	12/11/2009 15:00	Block Offer	46.00	28000.00	YES	1.00
Customer #1	12/11/2009 15:00	12/11/2009 19:00	Block Offer	65.00	28000.00	YES	4.00
Customer #1	12/16/2009 06:22	12/16/2009 08:45	Physical Shutdown	0.00	0.00		2.38
Customer #1	12/16/2009 08:45	12/16/2009 09:00	Block Offer	70.00	1000.00	YES	0.25
Customer #1	12/16/2009 09:00	12/16/2009 10:00	Block Offer	68.00	1000.00	YES	1.00
Customer #1	12/16/2009 10:00	12/16/2009 11:00	Block Offer	57.00	1000.00	YES	1.00
Customer #1	12/16/2009 11:00	12/16/2009 12:00	Block Offer	52.00	1000.00	YES	1.00
Customer #1	12/16/2009 12:00	12/16/2009 13:00	Block Offer	48.00	28000.00	YES	1.00
Customer #1	12/17/2009 06:10	12/17/2009 11:00	Block Offer	68.00	28000.00	YES	4.83
Customer #1	12/17/2009 11:00	12/17/2009 12:00	Block Offer	50.00	28000.00	YES	1.00
Customer #1	01/04/2010 07:00	01/04/2010 12:30	Block Offer	140.00	0.00	NO	5.50
Customer #1	01/04/2010 07:00	01/04/2010 12:30	Block Offer	140.00	0.00	NO	5.50
Customer #1	01/04/2010 12:30	01/04/2010 16:00	Block Offer	60.00	28000.00	YES	3.50
Customer #1	01/04/2010 12:30	01/04/2010 16:00	Block Offer	60.00	6000.00	YES	3.50
Customer #1	01/04/2010 16:00	01/04/2010 21:00	Block Offer	90.00	12000.00	YES	5.00
Customer #1	01/04/2010 16:00	01/04/2010 21:00	Block Offer	90.00	20000.00	YES	5.00
Customer #1	01/05/2010 05:21	01/05/2010 08:00	Physical Shutdown	0.00	0.00		2.65
Customer #1	01/05/2010 05:24	01/05/2010 08:00	Physical Shutdown	0.00	0.00		2.60
Customer #1	01/05/2010 08:00	01/05/2010 19:00	Block Offer	76.00	28000.00	YES	11.00
Customer #1	01/05/2010 08:00	01/05/2010 19:00	Block Offer	76.00	17000.00	YES	11.00
Customer #1	01/06/2010 06:15	01/06/2010 07:00	Physical Shutdown	0.00	0.00		0.75
Customer #1	01/06/2010 06:15	01/06/2010 07:00	Physical Shutdown	0.00	0.00		0.75
Customer #1	01/06/2010 07:00	01/06/2010 12:00	Block Offer	78.00	17000.00	YES	5.00
Customer #1	01/06/2010 07:00	01/06/2010 12:00	Block Offer	78.00	28000.00	YES	5.00
Customer #1	01/06/2010 12:00	01/06/2010 16:00	Block Offer	62.00	28000.00	YES	4.00
Customer #1	01/06/2010 12:00	01/06/2010 16:00	Block Offer	62.00	17000.00	YES	4.00
Customer #1	01/06/2010 16:00	01/06/2010 20:00	Block Offer	77.00	17000.00	YES	4.00
Customer #1	01/06/2010 16:00	01/06/2010 20:00	Block Offer	77.00	28000.00	YES	4.00
Customer #1	01/07/2010 06:00	01/07/2010 07:00	Hourly Offer	65.00	1000.00	YES	1.00
Customer #1	01/07/2010 06:00	01/07/2010 07:00	Hourly Offer	65.00	17000.00	YES	1.00
Customer #1	01/07/2010 07:00	01/07/2010 11:00	Block Offer	70.00	17000.00	YES	4.00
Customer #1	01/07/2010 10:00	01/07/2010 11:00	Hourly Offer	70.00	28000.00	YES	1.00
Customer #1	01/07/2010 11:00	01/07/2010 12:00	Hourly Offer	65.00	17000.00	YES	1.00
Customer #1	01/07/2010 11:00	01/07/2010 12:00	Hourly Offer	65.00	28000.00	YES	1.00
Customer #1	01/08/2010 06:00	01/08/2010 20:00	Block Offer	87.00	28000.00	YES	14.00
Customer #1	01/08/2010 06:00	01/08/2010 20:00	Block Offer	87.00	17000.00	YES	14.00
Customer #1	01/11/2010 06:00	01/11/2010 10:00	Physical Shutdown	0.00	0.00		4.00
Customer #1	01/11/2010 06:00	01/11/2010 10:00	Physical Shutdown	0.00	0.00		4.00
Customer #1	01/11/2010 10:00	01/11/2010 12:00	Block Offer	86.00	17000.00	YES	2.00
Customer #1	01/11/2010 10:00	01/11/2010 12:00	Block Offer	86.00	28000.00	YES	2.00
Customer #1	01/11/2010 12:00	01/11/2010 15:30	Physical Shutdown	0.00	0.00		3.50
Customer #1	01/11/2010 12:00	01/11/2010 15:30	Physical Shutdown	0.00	0.00		3.50
Customer #1	01/12/2010 06:00	01/12/2010 08:00	Physical Shutdown	0.00	0.00		2.00
Customer #1	01/12/2010 06:00	01/12/2010 08:00	Physical Shutdown	0.00	0.00		2.00
Customer #1	01/12/2010 08:00	01/12/2010 12:00	Block Offer	85.00	17000.00	YES	4.00
Customer #1	01/12/2010 08:00	01/12/2010 12:00	Block Offer	85.00	1000.00	YES	4.00
Customer #1	01/13/2010 07:00	01/13/2010 11:00	Block Offer	70.00	28000.00	YES	4.00
Customer #1	01/13/2010 07:00	01/13/2010 11:00	Block Offer	70.00	10000.00	YES	4.00
Customer #1	01/14/2010 06:30	01/14/2010 09:00	Physical Shutdown	0.00	0.00		2.50
Customer #1	01/14/2010 09:00	01/14/2010 11:00	Block Offer	56.00	17000.00	YES	2.00

Interruptions From 04/01/2007 To 03/31/2012

Company (1)	*Start Date/Time* (2)	*End Date/Time* (3)	*Offer Type* (4)	*Offer Price* (5)	*KW Hrs Taken* (6)	*Offer Accepted* (7)	*Hours* (8)
Customer #1	01/27/2010 07:30	01/27/2010 08:00	Physical Shutdown	0.00	0.00		0.50
Customer #1	01/27/2010 07:30	01/27/2010 08:00	Physical Shutdown	0.00	0.00		0.50
Customer #1	01/27/2010 08:00	01/27/2010 09:00	Hourly Offer	54.00	15000.00	YES	1.00
Customer #1	01/27/2010 08:00	01/27/2010 09:00	Hourly Offer	54.00	28000.00	YES	1.00
Customer #1	01/27/2010 09:00	01/27/2010 10:00	Hourly Offer	58.00	28000.00	YES	1.00
Customer #1	01/27/2010 09:00	01/27/2010 10:00	Hourly Offer	58.00	18000.00	YES	1.00
Customer #1	01/27/2010 10:00	01/27/2010 11:00	Hourly Offer	45.00	28000.00	YES	1.00
Customer #1	01/27/2010 10:00	01/27/2010 11:00	Hourly Offer	45.00	18000.00	YES	1.00
Customer #1	01/29/2010 06:15	01/29/2010 07:00	Hourly Offer	48.00	17000.00	YES	0.75
Customer #1	01/29/2010 06:15	01/29/2010 07:00	Block Offer	48.00	28000.00	YES	0.75
Customer #1	01/29/2010 07:00	01/29/2010 08:00	Hourly Offer	63.00	17000.00	YES	1.00
Customer #1	01/29/2010 07:00	01/29/2010 08:00	Hourly Offer	63.00	28000.00	YES	1.00
Customer #1	01/29/2010 08:00	01/29/2010 09:00	Hourly Offer	65.00	17000.00	YES	1.00
Customer #1	01/29/2010 08:00	01/29/2010 09:00	Hourly Offer	65.00	28000.00	YES	1.00
Customer #1	01/29/2010 09:00	01/29/2010 14:00	Block Offer	48.00	17000.00	YES	5.00
Customer #1	01/29/2010 09:00	01/29/2010 14:00	Block Offer	48.00	28000.00	YES	5.00
Customer #1	01/29/2010 15:00	01/29/2010 20:00	Block Offer	70.00	17000.00	YES	5.00
Customer #1	01/29/2010 15:00	01/29/2010 20:00	Block Offer	70.00	28000.00	YES	5.00
Customer #1	02/01/2010 06:00	02/01/2010 07:00	Hourly Offer	60.00	17000.00	YES	1.00
Customer #1	02/01/2010 06:00	02/01/2010 07:00	Hourly Offer	60.00	32000.00	YES	1.00
Customer #1	02/01/2010 07:00	02/01/2010 08:00	Hourly Offer	62.00	32000.00	YES	1.00
Customer #1	02/01/2010 07:00	02/01/2010 08:00	Hourly Offer	62.00	17000.00	YES	1.00
Customer #1	02/01/2010 08:00	02/01/2010 09:00	Hourly Offer	59.00	17000.00	YES	1.00
Customer #1	02/01/2010 08:00	02/01/2010 09:00	Hourly Offer	59.00	32000.00	YES	1.00
Customer #1	02/01/2010 09:00	02/01/2010 10:00	Hourly Offer	58.00	17000.00	YES	1.00
Customer #1	02/01/2010 09:00	02/01/2010 10:00	Hourly Offer	58.00	32000.00	YES	1.00
Customer #1	02/01/2010 10:00	02/01/2010 11:00	Hourly Offer	52.00	32000.00	YES	1.00
Customer #1	02/01/2010 10:00	02/01/2010 11:00	Hourly Offer	52.00	17000.00	YES	1.00
Customer #1	05/25/2010 13:00	05/25/2010 17:00	Block Offer	69.00	20000.00	YES	4.00
Customer #1	05/25/2010 13:00	05/25/2010 17:00	Block Offer	69.00	1000.00	YES	4.00
Customer #1	05/26/2010 14:40	05/26/2010 16:05	Physical Shutdown	0.00	0.00		1.42
Customer #1	05/26/2010 14:42	05/26/2010 16:05	Physical Shutdown	0.00	0.00		1.38
Customer #1	06/14/2010 12:00	06/14/2010 15:00	Block Offer	82.00	20000.00	YES	3.00
Customer #1	06/14/2010 12:00	06/14/2010 15:00	Block Offer	82.00	1000.00	YES	3.00
Customer #1	06/15/2010 13:30	06/15/2010 16:00	Physical Shutdown	0.00	0.00		2.50
Customer #1	06/15/2010 13:30	06/15/2010 16:00	Physical Shutdown	0.00	0.00		2.50
Customer #1	07/23/2010 11:00	07/23/2010 18:00	Block Offer	76.00	1000.00	YES	7.00
Customer #1	07/23/2010 11:00	07/23/2010 18:00	Block Offer	76.00	21000.00	YES	7.00
Customer #1	11/04/2010 06:12	11/04/2010 08:15	Physical Curtailment	0.00	0.00		2.05
Customer #1	12/14/2010 06:30	12/14/2010 08:06	Physical Curtailment	0.00	0.00		1.60
Customer #2	05/10/2007 13:00	05/10/2007 21:00	Block Offer	105.00	20,000.00	YES	8.00
Customer #2	07/06/2007 11:00	07/06/2007 18:00	Block Offer	85.00	21,000.00	YES	7.00
Customer #2	07/09/2007 10:00	07/09/2007 11:00	Block Offer	125.00	19,000.00	YES	1.00
Customer #2	07/09/2007 11:00	07/09/2007 19:00	Block Offer	125.00	21,000.00	YES	8.00
Customer #2	07/10/2007 10:00	07/10/2007 19:00	Block Offer	112.00	21,000.00	YES	9.00
Customer #2	07/17/2007 13:00	07/17/2007 19:00	Block Offer	80.00	20,000.00	YES	6.00
Customer #2	07/19/2007 10:00	07/19/2007 13:00	Block Offer	95.00	20,000.00	YES	3.00
Customer #2	07/19/2007 13:00	07/19/2007 14:40	Block Offer	95.00	14,000.00	YES	1.67
Customer #2	07/19/2007 14:40	07/19/2007 17:00	Block Offer	95.00	20,000.00	YES	2.33
Customer #2	08/06/2007 12:20	08/06/2007 17:00	Physical Shutdown	0.00	0.00		4.67

Interruptions From 04/01/2007 To 03/31/2012

Company (1)	*Start Date/Time* (2)	*End Date/Time* (3)	*Offer Type* (4)	*Offer Price* (5)	*KW Hrs Taken* (6)	*Offer Accepted* (7)	*Hours* (8)
Customer #2	08/07/2007 12:00	08/07/2007 18:00	Block Offer	142.00	21,000.00	YES	6.00
Customer #2	08/08/2007 12:00	08/08/2007 18:00	Block Offer	130.00	21,000.00	YES	6.00
Customer #2	08/09/2007 12:00	08/09/2007 18:00	Block Offer	163.00	21,000.00	YES	6.00
Customer #2	08/10/2007 12:00	08/10/2007 18:00	Block Offer	102.00	21,000.00	YES	6.00
Customer #2	08/13/2007 12:00	08/13/2007 18:00	Block Offer	115.00	21,000.00	YES	6.00
Customer #2	08/14/2007 11:00	08/14/2007 20:00	Block Offer	90.00	21,000.00	YES	9.00
Customer #2	08/15/2007 12:15	08/15/2007 18:20	Physical Shutdown	0.00	0.00		6.08
Customer #2	08/16/2007 12:00	08/16/2007 18:00	Block Offer	107.00	15,000.00	YES	6.00
Customer #2	08/22/2007 14:00	08/22/2007 15:00	Hourly Offer	110.00	13,000.00	YES	1.00
Customer #2	08/22/2007 15:00	08/22/2007 16:00	Hourly Offer	105.00	14,000.00	YES	1.00
Customer #2	08/22/2007 16:00	08/22/2007 17:00	Hourly Offer	102.00	14,000.00	YES	1.00
Customer #2	08/22/2007 17:00	08/22/2007 18:00	Hourly Offer	115.00	11,000.00	YES	1.00
Customer #2	08/22/2007 18:00	08/22/2007 19:00	Hourly Offer	110.00	11,000.00	YES	1.00
Customer #2	08/23/2007 12:00	08/23/2007 20:00	Block Offer	130.00	14,000.00	YES	8.00
Customer #2	08/24/2007 12:00	08/24/2007 18:00	Block Offer	100.00	18,000.00	YES	6.00
Customer #2	10/08/2007 13:40	10/08/2007 14:50	Physical Shutdown	0.00	0.00		1.17
Customer #2	06/09/2008 12:00	06/09/2008 18:00	Physical Shutdown	0.00	0.00		6.00
Customer #2	07/29/2008 12:00	07/29/2008 17:00	Block Offer	150.00	20,000.00	YES	5.00
Customer #2	08/01/2008 11:00	08/01/2008 13:00	Block Offer	135.00	20,000.00	YES	2.00
Customer #2	08/01/2008 13:20	08/01/2008 14:00	Physical Shutdown	0.00	0.00		0.67
Customer #2	08/01/2008 14:00	08/01/2008 18:00	Block Offer	160.00	20,000.00	YES	4.00
Customer #2	08/04/2008 12:00	08/04/2008 20:00	Block Offer	115.00	20,000.00	YES	8.00
Customer #2	08/05/2008 11:00	08/05/2008 19:00	Block Offer	120.00	21,000.00	YES	8.00
Customer #2	08/06/2008 10:00	08/06/2008 16:00	Block Offer	115.00	16,000.00	YES	6.00
Customer #2	08/07/2008 10:00	08/07/2008 16:00	Block Offer	119.00	20,000.00	YES	6.00
Customer #2	08/20/2008 12:00	08/20/2008 19:00	Block Offer	78.00	12,000.00	YES	7.00
Customer #2	08/21/2008 11:00	08/21/2008 18:00	Block Offer	79.50	18,000.00	YES	7.00
Customer #2	09/02/2008 12:00	09/02/2008 20:00	Block Offer	120.00	20,000.00	YES	8.00
Customer #2	09/03/2008 12:00	09/03/2008 20:00	Block Offer	92.00	21,000.00	YES	8.00
Customer #2	06/02/2009 13:00	06/02/2009 17:00	Block Offer	44.00	0.00	NO	4.00
Customer #2	08/27/2009 11:00	08/27/2009 18:00	Block Offer	38.00	18,000.00	YES	7.00
Customer #2	01/04/2010 07:00	01/04/2010 12:30	Block Offer	140.00	0.00	NO	5.50
Customer #2	01/04/2010 12:30	01/04/2010 16:00	Block Offer	60.00	6,000.00	YES	3.50
Customer #2	01/04/2010 16:00	01/04/2010 21:00	Block Offer	90.00	12,000.00	YES	5.00
Customer #2	01/05/2010 05:21	01/05/2010 08:00	Physical Shutdown	0.00	0.00		2.65
Customer #2	01/05/2010 08:00	01/05/2010 19:00	Block Offer	76.00	17,000.00	YES	11.00
Customer #2	01/06/2010 06:15	01/06/2010 07:00	Physical Shutdown	0.00	0.00		0.75
Customer #2	01/06/2010 07:00	01/06/2010 12:00	Block Offer	78.00	17,000.00	YES	5.00
Customer #2	01/06/2010 12:00	01/06/2010 16:00	Block Offer	62.00	17,000.00	YES	4.00
Customer #2	01/06/2010 16:00	01/06/2010 20:00	Block Offer	77.00	17,000.00	YES	4.00
Customer #2	01/07/2010 06:00	01/07/2010 07:00	Hourly Offer	65.00	17,000.00	YES	1.00
Customer #2	01/07/2010 07:00	01/07/2010 11:00	Block Offer	70.00	17,000.00	YES	4.00
Customer #2	01/07/2010 11:00	01/07/2010 12:00	Hourly Offer	65.00	17,000.00	YES	1.00
Customer #2	01/08/2010 06:00	01/08/2010 20:00	Block Offer	87.00	17,000.00	YES	14.00
Customer #2	01/11/2010 06:00	01/11/2010 10:00	Physical Shutdown	0.00	0.00		4.00
Customer #2	01/11/2010 10:00	01/11/2010 12:00	Block Offer	86.00	17,000.00	YES	2.00
Customer #2	01/11/2010 12:00	01/11/2010 15:30	Physical Shutdown	0.00	0.00		3.50
Customer #2	01/12/2010 06:00	01/12/2010 08:00	Physical Shutdown	0.00	0.00		2.00

Interruptions From 04/01/2007 To 03/31/2012

Company (1)	*Start Date/Time* (2)	*End Date/Time* (3)	*Offer Type* (4)	*Offer Price* (5)	*KW Hrs Taken* (6)	*Offer Accepted* (7)	*Hours* (8)
Customer #2	01/12/2010 08:00	01/12/2010 12:00	Block Offer	85.00	17,000.00	YES	4.00
Customer #2	01/13/2010 07:00	01/13/2010 11:00	Block Offer	70.00	10,000.00	YES	4.00
Customer #2	01/14/2010 06:30	01/14/2010 09:00	Physical Shutdown	0.00	0.00		2.50
Customer #2	01/14/2010 09:00	01/14/2010 11:00	Block Offer	56.00	17,000.00	YES	2.00
Customer #2	01/27/2010 07:30	01/27/2010 08:00	Physical Shutdown	0.00	0.00		0.50
Customer #2	01/27/2010 08:00	01/27/2010 09:00	Hourly Offer	54.00	15,000.00	YES	1.00
Customer #2	01/27/2010 09:00	01/27/2010 10:00	Hourly Offer	58.00	18,000.00	YES	1.00
Customer #2	01/27/2010 10:00	01/27/2010 11:00	Hourly Offer	45.00	18,000.00	YES	1.00
Customer #2	01/29/2010 06:15	01/29/2010 07:00	Hourly Offer	48.00	17,000.00	YES	0.75
Customer #2	01/29/2010 07:00	01/29/2010 08:00	Hourly Offer	63.00	17,000.00	YES	1.00
Customer #2	01/29/2010 08:00	01/29/2010 09:00	Hourly Offer	65.00	17,000.00	YES	1.00
Customer #2	01/29/2010 09:00	01/29/2010 14:00	Block Offer	48.00	17,000.00	YES	5.00
Customer #2	01/29/2010 15:00	01/29/2010 20:00	Block Offer	70.00	17,000.00	YES	5.00
Customer #2	02/01/2010 06:00	02/01/2010 07:00	Hourly Offer	60.00	17,000.00	YES	1.00
Customer #2	02/01/2010 07:00	02/01/2010 08:00	Hourly Offer	62.00	17,000.00	YES	1.00
Customer #2	02/01/2010 08:00	02/01/2010 09:00	Hourly Offer	59.00	17,000.00	YES	1.00
Customer #2	02/01/2010 09:00	02/01/2010 10:00	Hourly Offer	58.00	17,000.00	YES	1.00
Customer #2	02/01/2010 10:00	02/01/2010 11:00	Hourly Offer	52.00	17,000.00	YES	1.00
Customer #2	05/25/2010 13:00	05/25/2010 17:00	Block Offer	69.00	20,000.00	YES	4.00
Customer #2	05/26/2010 14:40	05/26/2010 16:05	Physical Shutdown	0.00	0.00		1.42
Customer #2	06/14/2010 12:00	06/14/2010 15:00	Block Offer	82.00	20,000.00	YES	3.00
Customer #2	06/15/2010 13:30	06/15/2010 16:00	Physical Shutdown	0.00	0.00		2.50
Customer #2	07/23/2010 13:00	07/23/2010 21:00	Physical Shutdown	76.00	21,000.00		7.00
Customer #2	11/04/2010 06:28	11/04/2010 08:34	Physical Curtailment	0.00	0.00		2.10
Customer #2	12/14/2010 07:00	12/14/2010 08:27	Physical Curtailment	0.00	0.00		1.45
Customer #2	06/07/2011 13:00	06/07/2011 19:00	Buy Through Curtailment	0.00	0.00		6.00
Customer #2	06/08/2011 11:00	06/08/2011 19:00	Buy Through Curtailment	0.00	0.00		8.00
Customer #2	06/09/2011 11:00	06/09/2011 19:00	Buy Through Curtailment	0.00	0.00		8.00
Customer #2	07/11/2011 12:00	07/11/2011 19:00	Buy Through Curtailment	0.00	0.00		7.00
Customer #2	07/12/2011 12:01	07/12/2011 16:00	Buy Through Curtailment	0.00	0.00		3.98
Customer #2	07/18/2011 13:00	07/18/2011 19:00	Buy Through Curtailment	0.00	0.00		6.00
Customer #2	07/20/2011 11:00	07/20/2011 19:00	Buy Through Curtailment	0.00	0.00		8.00
Customer #2	07/21/2011 10:00	07/21/2011 13:30	Buy Through Curtailment	0.00	0.00		3.50
Customer #2	07/21/2011 13:30	07/21/2011 14:25	Physical Curtailment	0.00	0.00		0.92
Customer #2	07/21/2011 14:25	07/21/2011 20:30	Buy Through Curtailment	0.00	0.00		6.08
Customer #2	07/22/2011 11:00	07/22/2011 18:00	Buy Through Curtailment	0.00	0.00		7.00
Customer #2	07/27/2011 10:00	07/27/2011 19:00	Buy Through Curtailment	0.00	0.00		9.00
Customer #2	07/28/2011 10:00	07/28/2011 20:00	Buy Through Curtailment	0.00	0.00		10.00
Customer #2	07/29/2011 11:00	07/29/2011 19:00	Buy Through Curtailment	0.00	0.00		8.00
Customer #2	08/01/2011 11:00	08/01/2011 19:00	Buy Through Curtailment	0.00	0.00		8.00
Customer #2	08/02/2011 11:00	08/02/2011 19:00	Buy Through Curtailment	0.00	0.00		8.00
Customer #2	08/08/2011 12:00	08/08/2011 18:00	Buy Through Curtailment	0.00	0.00		6.00
Customer #2	09/01/2011 12:00	09/01/2011 19:00	Buy Through Curtailment	0.00	0.00	YES	7.00
Customer #2	09/02/2011 12:00	09/02/2011 19:00	Buy Through Curtailment	0.00	0.00	YES	7.00

Total Hours *1234.58*

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-47

Responding Witness: Lonnie E. Bellar

Q1-47. Please provide a timeline for the last 10 years showing by year each curtailable/interruptible rate or rider offered by LG&E, the number of customers served under each rate/rider, and the total MW of interruptible or curtailable load served under each curtailable/interruptible rate/rider.

A1-47. See table below.

3/1/2000	7/1/2004	CSR	LC	LC-TOD	LP	LP-TOD	No. Customers	Maximum Curtailable MW
			$3.30	$3.30	$3.30	$ 3.30	3	71.0
			Trans	Pri				
7/1/2004	2/6/2009	CSR1	$3.10	$3.20			2	69.2
		CSR2	$3.98	$4.05			0	0
		CSR3	$3.10	$3.20			0	0
2/6/2009	8/1/2010	CSR1	$5.10	$5.20			2	69.2
		CSR2	$5.48	$5.55			0	0
		CSR3	$3.10	$3.20			0	0
8/1/2010	current	CSR10	$5.40	$5.50			1	46.5
		CSR30	$4.30	$4.40			1	22.7

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

**Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012**

Question No. 1-49

Responding Witness: Paul W. Thompson

Q1-49. Please explain in detail how LG&E (acting alone or in conjunction with affiliates) treats interruptible/curtailable load in:

a. Developing its long-run load forecast?

b. Determining its long-run need for future supply-side resources?

c. Determining its need for operating reserve capacity?

d. Providing ancillary services?

e. Determining whether such load qualifies as spinning reserve?

A1-49. a. In the long-run load forecast, curtailable customers are viewed as a resource that can be called upon after all other resources have been exhausted. This is done to comply with the specific language of the most recently approved curtailable service riders, CSR 10 and CSR 30. The forecasted usage for curtailable customers is based on historical usage and specific customer information.

b. Despite the fact that existing CSR customers can terminate their CSR contracts with only six months' notice, the Companies assume that the CSR contracts will continue to exist in the future and consider the availability of CSR capacity in the determination of its long-run need for future supply-side resources.

c. Interruptible/curtailable load is assumed to be available on a limited basis for operating reserve capacity during 'system reliability' events. The *LG&E and KU 2011 Reserve Margin Study* submitted as part of the 2011 Integrated Resource Plan considered the need to carry operating reserve capacity. The availability of CSR capacity was considered in meeting this need.

d. LG&E does not consider interruptible/curtailable load in providing ancillary services.

e. The Companies do not have real-time interruptible/curtailable load information. Therefore, it cannot be considered as spinning reserves.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-50

Responding Witness: Paul W. Thompson

Q1-50. Identify all reserve sharing and/or coordination arrangements that LG&E has with other utility systems or organizations, and provide a current copy or identify a Web link to a current copy of all agreements related to such arrangements.

A1-50. The Company provided the requested information in Case No. 2009-00549 in its response to KIUC DR 1-7, dated March 15, 2010, which the Company hereby incorporates by reference. The Company provided the requested information in Case No. 2009-00549 under a petition for confidential protection.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-51

Responding Witness: Robert M. Conroy

Q1-51. Please explain in detail how LG&E treats curtailment buy-though revenues in setting base rates. Please explain in detail how buy-through revenues are treated in LG&E's Fuel Adjustment Clause. Please state whether LG&E applies an Environmental Surcharge or Fuel Adjustment Charge to buy-through purchases.

A1-51. The Company reduces purchased power expense and kWh by the amount of buy-through power to ensure that retail customers' FAC reflects only those power purchases used to supply native load. Buy-through power charges are not included in revenue subject to the Environmental Surcharge. The Fuel Adjustment Charge is not applied to buy-through energy.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-52

Responding Witness: Robert M. Conroy

Q1-52. Please identify and explain in detail how LG&E treats test-year curtailment buy-though revenues in the electric cost-of-service study filed in this case.

A1-52. Curtailment buy-through revenues are included in Sales to Ultimate Consumers shown on page 25 and 26 of Conroy Exhibit C3.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-53

Responding Witness: Robert M. Conroy

Q1-53. Please identify and explain in detail how LG&E treats test-year curtailment credits paid to CSR10 and CSR30 customers in the electric cost-of-service study filed in this case.

A1-53. Curtailment credits are specifically assigned to the customers who received curtailment credits during the test year. See pages 25-26 of Conroy Exhibit C3.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-54

Responding Witness: Lonnie E. Bellar

Q1-54. Please identify and explain in detail all situations other than a system reliability event in which LG&E would need or want to physically curtail load under the proposed CSR riders.

A1-54. See the response to PSC 2-83(c).

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-55

Responding Witness: Lonnie E. Bellar

Q1-55. Since Riders CSR10 and CSR30 were first approved by the Commission, please provide the following for each instance in which LG&E would have issued a physical curtailment request but was prevented from doing so by restrictions in each rider limiting the basis for a physical curtailment:

a. Date, time, and duration of occurrence.

b. Reason(s) (for example, operating, market, and/or reliability conditions) for desiring a physical curtailment.

c. MW of CSR load needed to alleviate conditions listed in item (b) above.

d. Action(s) taken by LG&E other than physical curtailment of CSR load to alleviate conditions listed in item (b) above.

A1-55. Circumstances surrounding potential curtailment events in which the Company was not able to curtail CSR customers are not currently tracked.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-56

Responding Witness: Lonnie E. Bellar

Q1-56. Please provide LG&E's current estimated cost in 2012 dollars of an installed combustion turbine. Provide all workpapers, studies, analyses, and documents supporting and/or underlying this estimate.

A1-56. LG&E's current estimated cost of an installed CT in 2012 dollars is $882/kW, which is based on the Companies' 2011 Integrated Resource Plan cost of an installed combustion turbine escalated from 2010 dollars. For supporting documentation, please refer to Companies' 2011 Integrated Resource Plan (Case No. 2011-00140) in the Supply-Side Analysis contained in Volume III. See also the response to Question No. 60.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-58

Responding Witness: Lonnie E. Bellar

Q1-58. Please provide the estimated fixed O&M for a new combustion turbine in 2012 dollars. Provide all workpapers, studies, analyses, and documents supporting and/or underlying this response.

A1-58. The estimated fixed O&M for a new CT in 2012 dollars is $5.14/kW, which is based on the Companies' 2011 Integrated Resource Plan fixed O&M for a new CT escalated from 2010 dollars. For supporting documentation, please refer to Companies' 2011 Integrated Resource Plan (Case No. 2011-00140) in the Supply-Side Analysis contained in Volume III. See also the response to Question No. 60.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated July 31, 2012

Question No. 1-59

Responding Witness: Lonnie E. Bellar

Q1-59. Please provide LG&E's required reserve margin for capacity planning. Provide all workpapers, studies, analyses, and documents supporting and/or underlying this response.

A1-59. The Company's required reserve margin range for capacity planning is 15-17%. Please see the *LG&E and KU 2011 Reserve Margin Study* submitted as part of the 2011 Integrated Resource Plan, Case No. 2011-00140. See also the response to Question No. 60.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

**Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012**

Question No. 1-61

Responding Witness: Lonnie E. Bellar

Q1-61. Referring to LG&E's CSR riders:

a. Please identify the maximum MW eligible for service under the proposed CRS riders.

b. Explain in detail the rationale for the total requirements limit in the Availability of Service section of CSR riders.

c. For each day of the test year in which LG&E called a curtailment with an economic buy-through, please identify the NGP for that day and provide a copy of the source data for the NGP.

d. Provide all workpapers, studies, analyses, and documents supporting and/or underlying LG&E's decision to price buy-though power using an automatic, formula-based mechanism.

e. Provide all workpapers, studies, analyses, and documents supporting and/or underlying the heat rate reflected in the proposed buy-through formula.

f. Provide all documents relating to any customer comments and/or feedback that LG&E received regarding the proposed reductions in rate credits under the CSR riders prior to LG&E's deciding to include the reduced credits in the CSR riders.

g. Describe in detail conditions that will trigger LG&E's decision to call a buy-through curtailment.

h. Describe in detail conditions that will trigger LG&E's decision to call a physical curtailment.

A1-61. a. The maximum MW eligible for service is 100 in excess of the amount currently served.

b. The total requirements limit is intended to limit the Company's risk exposure given the restrictions and termination rights that are components of the rider.

c. During the test year, LG&E called a curtailment on the following days:

6/7/2011
6/8/2011
6/9/2011
7/11/2011
7/12/2011
7/18/2011
7/20/2011
7/21/2011
7/22/2011
7/27/2011
7/28/2011
7/29/2011
8/1/2011
8/2/2011
8/8/2011
9/1/2011
9/2/2011

LG&E obtained the NGP for each of the days listed above from Platt's Gas Daily. Because the NGP and the corresponding source data are proprietary to Platt's, LG&E cannot provide this information without Platt's permission. LG&E has requested, but not yet received, the required permission. LG&E will supplement this response to provide the NGP and corresponding source data if and when permission is received.

d. There are no work papers. The business reasons for this approach were ease of implementation for the Companies and to provide price transparency for customers.

e. Though no studies were performed, the heat rate in the proposed buy through formula corresponds to the heat rate of several of the Companies' combustion turbines.

f. No such documents exist.

g. Buy-through curtailment requests under the CSR rider are issued at LG&E's sole discretion for economic reasons typically at times of high load and high gas prices.

h. Currently, LG&E issues physical curtailment requests according to the criteria stated in its tariff, i.e., during "system reliability events." LG&E's proposal is to be able to issue physical curtailment requests at its discretion for reliability or economic reasons.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-62

Responding Witness: Lonnie E. Bellar

Q1-62. Please identify the terms and provisions that LG&E would insist on including in the proposed CSR riders in exchange for leaving the current CSR curtailable rate credits unchanged. Please explain the response in detail.

A1-62. LG&E has not performed the analysis necessary to respond to this request. It is possible that multiple hypothetical combinations of terms and provisions could support maintaining the current CSR credits, or that no such combination could support it. LG&E did not seek to find such a combination because supporting a particular level of CSR credits is not LG&E's objective; rather, LG&E's objective is to provide safe, reliable, and lowest-reasonable-cost service to all its customers. LG&E believes its overall CSR credit proposal furthers that objective.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-63

Responding Witness: Lonnie E. Bellar

Q1-63. Provide in native format all workpapers, studies, analyses, and documents supporting and/or underlying the $16 per kW Non-Compliance Charge in the proposed CSR riders.

A1-63. The $16 per kW Non-Compliance Charge was introduced in the proposed CSR rates filed in Case No. 2003-00434 and reflected approximately 4 months of the $4.05/kW primary voltage credit proposed in Case No. 2009-00549. See page 75 of Mr. William Steven Seelye's direct testimony in Case No. 2003-00433. The charge was introduced to ensure customer compliance when a curtailment is called and has remained the same since its implementation in 2003.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-64

Responding Witness: Lonnie E. Bellar

Q1-64. Referring to witness Bellar's direct testimony regarding the CSR riders:

a. Explain in detail why prices in the most recent PJM demand response auction are relevant for evaluating the credits in LG&E's proposed CSR riders.

b. Explain LG&E's understanding of how many hours of physical interruption/curtailment a demand response resource in PJM would be subject to in order to receive the demand response price developed in PJM's most recent demand response auction.

c. Does witness Bellar agree that the revenue requirement for LG&E's installed combustion turbine capacity in this case should reflect and/or approximate the current market price for demand response resources in PJM or other wholesale markets? Please explain the response in detail.

d. Does witness Bellar agree that the revenue requirement for LG&E's combustion turbine capacity in this case should reflect and/or approximate the current market price for combustion turbine resources in PJM or other wholesale markets? Please explain the response in detail.

e. Does witness Bellar agree (see Bellar direct at 21) that the CSR credits should reflect value of service pricing principles instead of cost-of-service pricing principles? Please explain the response in detail.

f. Does witness Bellar agree that the revenue requirement in this case for LG&E's installed generating resources should reflect value-of-service pricing principles instead of cost-of-service pricing principles? Please explain the response in detail.

g. Did witness Bellar and/or LG&E examine the potential customer-specific and service-area economic impacts of reducing the existing CSR credits? If such examinations were conducted, provide all workpapers, studies, analyses, and documents supporting and/or underlying the response. If such examinations were not conducted, please explain why not.

A1-64. a. As explained in Mr. Bellar's testimony, the PJM demand response auctin provides and indicator as to the value of demand response actions (or participation in LG&E's curtailable service riders). The auction results clearly demonstrate that current market conditions in PJM place a lower value on demand response options than is currently provided by LG&E's CSR rates.

b. See Attachment 1 provided in response to Question No. 1-44a.

c. No. The market price in wholesale demand markets will vary from month to month and from year to year. As explained on pages 21-22 of Mr. Bellar's direct testimony, the most recent PJM demand response auction generated a $3.83/kW-month result for 2014-2015, whereas the values in the auction were considerably less in 2012-2013 at $0.50/kW-month and $0.84/kW-month for 2013-2014.

d. See response to c.

e. CSR pricing should generally reflect cost of service principles. More specifically, CSR pricing should generally reflect the avoided cost associated with being able to curtail CSR load in a timely manner.

f. With respect to CSR service, value-of-service corresponds to the avoided cost of being able to curtail CSR load; therefore, value-of-service is equivalent to cost of service. See response to e.

g. LG&E has an obligation to serve all of its customers in the most cost-effective manner possible. For this reason, LG&E relies on its cost of service study to aid in designing rates, and does not attempt to design rates based on a customer-specific economic impact analysis of any proposed modifications. Furthermore, the Company does not have the local customer-specific financial data to perform such a study.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

**Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012**

Question No. 2.118

Responding Witness: Lonnie E. Bellar

Q2.118 Referring to LGE's response to KIUC 1-49(a):

a. Since LGE considers CSR customers a resource, please identify and describe the resource that CSR customers provide, identify who owns or has legal title to the resource, and explain in detail whether a CSR customer is restricted from selling this resource to a party other than LGE.

b. Please identify the "specific language" in the current CSR riders that cause LGE to view CSR customers as a resource. Please explain in detail whether eliminating this "specific language" would change how LGE treats CSR loads in its long-term load forecast.

A2.118 a.b. The Companies consider CSR customers to be a resource for long-term load forecasting purposes. Such customers are a "resource" for meeting load because they can be called upon to reduce load under certain conditions; however, the conditions under which the Companies may use the CSR-customer "resource" are significantly constraining:

> Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option during system reliability events. For the purposes of this rider, a system reliability event is any condition or occurrence: 1) that impairs KU and LG&E's ability to maintain service to contractually committed system load; 2) where KU and LG&E's ability to meet their compliance obligations with NERC reliability standards cannot otherwise be achieved; or 3) that KU and LG&E reasonably anticipate will last more than six hours and could require KU and LG&E to call upon automatic reserve sharing ("ARS") at some point during the event.

This conditioning language is the "specific language" to which LG&E's response to KIUC 1-49a referred. This language does not cause LG&E to view CSR customers as a resource; rather, it significantly constrains the usefulness of the CSR-customer resource, which is why LG&E has proposed to eliminate it.

Each CSR customer is a part of the overall "resource," and each customer owns its own portion of the resource. There is no legal title to such a "resource." But clearly LG&E does not own the "resource"; only a customer can decide whether to curtail its demand when requested and thereby create part of the CSR "resource."

Because LG&E is its customers' sole electric supplier, the CSR "resource" exists only when customers comply with LG&E's curtailment requests. Therefore, there is no other party to whom CSR customers could sell the "resource."

Elimination of the language would cause LG&E to change the way in which CSR customers are treated in its load forecast, allowing peak load to be reduced in proportion to available CSR load. See also the response to Question No. 2.117(d).

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012

Question No. 2.119

Responding Witness: Lonnie E. Bellar

Q2.119 Referring to LGE's response to KIUC 1-61(h), if the system reliability event condition were removed from the CSR riders, would LGE be allowed to physically interrupt a CSR customer if such interruption allowed LGE to make an off-system sale in which the sales price per kWh was greater than the average price per kWh that LGE would have received by serving the CSR customer? If the answer is yes, please explain in detail why interruptions for such off-system sales should be allowed by the Commission.

A2.119 Although making an off-system sale during an interruption of a CSR customer is not the objective of the physical interruption portion of the Companies' CSR program, under the CSR proposal in this case it would be possible. Also, see the response to Question No. 2.117b.

The credits provided to CSR customers are derived from an increase in revenue from other customers, thus if hours of physical interruption remain and in the Companies' business judgment the best use of those hours is to allow participation in the off-system market, it should be allowed. As always, the Companies should be allowed to maximize their resources to the benefit of all customers.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012

Question No. 2.120

Responding Witness: Lonnie E. Bellar

Q2.120 Referring to LGE's response to KIUC 1-64:

a. Does LGE have an obligation to serve interruptible (curtailable) load?

b. Please identify all ways in which LGE's obligation to serve CSR interruptible load differs from its obligation to serve firm retail load.

c. Please provide a response to KIUC 1-64(f) as asked.

d. Please state the definition of what

A2.120 a. Yes.

b. LG&E's obligation to serve CSR-interruptible load differs in two respects from its obligation to serve firm retail load: (1) LG&E may request a CSR customer to curtail its load for a certain number of hours each year with a buy-through option; and (2) LG&E may request a customer to physically curtail its load for a limited number of hours each year under certain circumstances. LG&E credits CSR customers monthly on a per-kW basis for the right to ask for such interruptions, and may charge a CSR customer a per-kW non-compliance penalty if the customer does not physically curtail its load during a physical curtailment request or during a buy-through curtailment request if the customer has not bought through. Please see P.S.C. Electric No. 8, Original Sheet Nos. 50 – 51.2.

c. The revenue requirement in this case for LG&E's installed generating resources should reflect cost-of-service principles. Please see LG&E's responses to KIUC 1-64(e) and (f) concerning appropriate CSR credit pricing.

d. N/A.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012

Question No. 2.121

Responding Witness: Lonnie E. Bellar

Q2.121 Referring to LGE's response to KIUC 1-65(a), please provide a response to the question as asked regarding the appropriateness of a 10 percent carrying cost.

A2.121 KIUC 1-65(a) asked:

> Referring to witness Bellar's direct testimony at 10-11:
>
> a. Please explain in detail why a 10 percent carrying cost is appropriate when evaluating the annualized cost of combustion turbine capacity available to LG&E.

The relevant portion of Mr. Bellar's testimony states, "The purchase price for the Bluegrass CTs was $222/kW, which, using a 10% carrying cost, would yield a CSR-equivalent value of $1.85/kW-month."

LG&E's response to KIUC 1-65(a) referred to LG&E's response to KIUC 1-57, which stated:

> LG&E and KU use a single fixed charge rate to evaluate supply side alternatives based on the Companies' cost of capital and tax rates. The levelized fixed charge rate for a combustion turbine is 9.62% (see attached). For supporting documentation, please refer to the Companies' 2011 Integrated Resource Plan (Case No. 2011-00140) in the Supply-Side Analysis contained in Volume III and the attached document for more information. See also the response to Question No. 60.

Mr. Bellar's testimony rounded 9.62% to 10% to simplify the carrying cost calculation. Using the more precise value of 9.62% yields a CSR-equivalent value of $1.78/kW-month.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Commission Staff's Second Request For Information
Dated July 31, 2012**

Case No. 2012-00222

Question No. 83

Responding Witness: Lonnie E. Bellar

Q-83. Refer to the discussion of the proposed changes to the CSRs beginning on page 19 of the Bellar Testimony.

a. Explain whether LG&E has discussed the proposed changes with its two CSR customers, and if so, the customers' response to the incentive offered by the proposed changes.

b. Pages 21 and 22 of the Bellar Testimony cite recent PJM demand response auction prices and the statement is made that the proposed CSR10 credit strikes a reasonable balance between capacity market prices and the desire to encourage demand response. Explain whether physical curtailments are generally necessary during high usage times when market prices would be at higher peak prices.

c. Page 22 of the Bellar Testimony states that LG&E proposed to eliminate the system reliability event restriction on its ability to request a physical curtailment. Explain why a physical curtailment would be needed absent a system reliability event.

A-83. a. LG&E's customer service representatives directly communicated the proposed changes to the customers that would be impacted at the time the rate case was being filed. Generally, customers' reactions included concern about the financial impact and an awareness of market conditions that caused LG&E to change rates.

b. Considering physical curtailments in LG&E's CSR tariffs are limited with respect to annual hours of usage, physical curtailments would generally be necessary during times of high usage which usually results in relatively high market peak prices.

c. Outside of a system reliability event in which physical curtailment would be necessary, the Company can choose to physically curtail load under the provisions of the proposed CSR rider anytime the economic benefit of curtailment would be greater than the marginal cost of production utilizing another resource, typically this would be a combustion turbine or a market purchase.

APPENDIX

QUALIFICATIONS OF

DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, VA

PREVIOUS POSITIONS

- Vice President, Hagler, Bailly & Company, Washington, DC
- Principal, Resource Consulting Group, Inc., Cambridge, MA
- Senior Associate, Resource Planning Associates, Inc., Cambridge, MA
- Economist, North Carolina Utilities Commission, Raleigh, NC

EDUCATION

College	Major	Degree
Wake Forest University	Economics	BA
North Carolina State University	Economics	ME
North Carolina State University	Economics	PhD

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in evaluating competitive market conditions, analyzing power and fuel requirements, prices, market operations, and transactions, developing product pricing strategies, setting rates for energy-related products and services, and negotiating power supply and natural gas contracts for private and public entities. He has participated in nearly 200 cases as an expert on competitive market issues, utility restructuring, power market planning and operations, utility mergers, rate design, cost of service, and management prudence before the Federal Energy Regulatory Commission, the General Accounting Office (now the Government Accountability Office), the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, the Linn County District Court of Iowa, and regulatory commissions in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Wyoming, and the District of Columbia. He has also prepared an expert report on behalf of the

United States regarding pricing and contract issues in a case before the United States Court of Federal Claims.

PARTICIPATION IN REGULATORY, ADMINISTRATIVE, AND COURT PROCEEDINGS

1. Kentucky Utilities, Inc., before the Kentucky Public Service Commission, Case No. 2012-00221 (2012), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
2. Louisville Gas and Electric Company, Inc., before the Kentucky Public Service Commission, Case No. 2012-00222 (2012), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
3. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 479 (2012), on behalf of Nucor Steel-Hertford, re cost of service and retail rate design.
4. Kansas City Power & Light Company, before the Missouri Public Service Commission, Case No. ER-2012-0174 (2012), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
5. Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 9286 (2012), on behalf of the General Services Administration, re retail cost recovery.
6. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 44075 (2012), on behalf of Steel Dynamics, Inc., re retail cost-of-service and fuel and purchased power cost recovery.
7. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 39896 (2012), on behalf of Texas Cities, re cost of service and retail rate design.
8. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1087 (2012), on behalf of the General Services Administration, re retail cost recovery.
9. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 474 (2011), on behalf of Nucor Steel-Hertford, re fuel rate adjustments.
10. Mid-Kansas Electric Company, before the Kansas Corporation Commission, Docket No. 11-GIME-597-GIE (2011),on behalf of Kansas Electric Power Cooperative, Inc., re local delivery service and operating agreements.

11. Duke Energy Corporation *et al.*, before the Federal Energy Regulatory Commission, Docket No. EC11-60-000 (2011), on behalf of the North Carolina Electric Membership Corporation, re merger-related market power issues.
12. Resale Power Group of Iowa *et al.*, before the Linn County District Court of Iowa, Case No. LACV 054271 (2011), on behalf of Central Iowa Power Cooperative, re compensation for unauthorized transmission access.
13. Columbus Southern Power Company *et al.*, before the Public Utilities Commission of Ohio, Case No. 11-346-EL-SSO *et al.*, (2011), on behalf of the OMA Energy Group., re standard service offer electric security plan rate design issues.
14. Appalachian Power Company and Wheeling Power Company, dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 11-0274-E-GI (2011), on behalf of Steel of West Virginia, Inc., re expanded net energy cost rate issues.
15. Rocky Mountain Power Company, before the Wyoming Public Service Commission, Docket No. 20000-384-ER-10 (2011), on behalf of Cimarex Energy Company, QEP Field Services Company, and Kinder Morgan Interstate Gas Transmission, re utility rates, cost-of-service, and resource acquisition issues.
16. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 43955 (2011), on behalf of Nucor Steel and Steel Dynamics, Inc., re utility-sponsored energy efficiency programs.
17. Kansas City Power & Light Company, before the Missouri Public Service Commission, Case No. ER-2010-0355 (2010), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
18. Appalachian Power Company and Wheeling Power Company, dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 10-0699-E-42T (2010), on behalf of Steel of West Virginia, Inc., re cost-of-service and rate design issues.
19. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 10-010-U (2010), on behalf of Arkansas Electric Energy Consumers, Inc., re industrial opt out of utility-sponsored energy efficiency programs.
20. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 38702 – FAC 62-S1 (2010), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.

21. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 459 (2010), on behalf of Nucor Steel-Hertford, re cost of service and retail rate design.
22. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 461 (2010), on behalf of Nucor Steel-Hertford, re fuel rate adjustments.
23. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 37744 (2010), on behalf of Texas Cities, re cost of service and retail rate design.
24. Kentucky Utilities, Inc., before the Kentucky Public Service Commission, Case No. 2009-00548 (2010), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
25. Louisville Gas and Electric Company, Inc., before the Kentucky Public Service Commission, Case No. 2009-00549 (2010), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
26. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 09-1948-EL-POR *et al.*, (2010), on behalf of Nucor Steel Marion, Inc., re energy efficiency and peak demand reduction portfolios.
27. Kauai Island Utility Cooperative, before the Hawaii Public Utilities Commission, Docket No. 2009-0050 (2010), on behalf of Kauai Marriott Resort & Beach Club, re retail cost allocation and rate design issues.
28. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 09-024-U (2009), on behalf of Arkansas Electric Energy Consumers, Inc., re power plant environmental retrofit.
29. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00030 (2009), on behalf of Steel Dynamics, Inc., re retail cost allocation and rate design issues.
30. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 09-906-EL-SSO (2009), on behalf of Nucor Steel Marion, Inc., re market rate offer.
31. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 456 (2009), on behalf of Nucor Steel-Hertford, re fuel cost adjustment.
32. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00068 (2009), on behalf of Steel Dynamics, Inc., re demand response programs.

33. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 43750 (2009), on behalf of Steel Dynamics, Inc., re wind power purchased power agreement.
34. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 07-085-TF (2009), on behalf of Arkansas Electric Energy Consumers, Inc., re energy efficiency cost recovery.
35. CenterPoint Energy Arkansas Gas, before the Arkansas Public Service Commission, Docket No. 07-081-TF (2009), on behalf of Arkansas Gas Consumers, Inc., re energy efficiency cost recovery.
36. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2009-261-E (2009), on behalf of CMC Steel-SC, re DSM cost recovery surcharge.
37. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 38707 FAC81 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
38. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1076 (2009), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.
39. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00039 (2009), on behalf of Steel Dynamics, Inc., re environmental and reliability cost recovery.
40. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 38702 – FAC 63 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
41. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-302-00038 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
42. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2008-302-E (2008), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.
43. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2008-196-E (2008), on behalf of CMC Steel-SC, re base load review order for a nuclear facility.
44. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 08-935-EL-SSO *et al.* (2008), on behalf of Nucor Steel Marion, Inc., re standard service offer via an electric security plan.

45. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 08-936-EL-SSO (2008), on behalf of Nucor Steel Marion, Inc., re market rate offer via a competitive bidding process.
46. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2008), on behalf of CMC Steel Alabama, Nucor Steel Birmingham, Inc., and Nucor Steel Tuscaloosa, Inc, re energy cost recovery.
47. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 35269 (2008), on behalf of Texas Cities, re jurisdictional allocation of system agreement payments.
48. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 43374 (2008), on behalf of Nucor Steel and Steel Dynamics, Inc., re alternative regulatory plan.
49. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 34800 (2008), on behalf of Texas Cities, re affiliate transactions.
50. Commonwealth Edison Company, before the Illinois Commerce Commission, Docket No. 07-0566 (2008), on behalf of Nucor Steel Kankakee, Inc., re cost-of-service and rate design issues.
51. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 07-0551-EL-AIR *et al.* (2008), on behalf of Nucor Steel Marion, Inc., re cost-of-service and rate design issues.
52. Appalachian Power Company dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 06-0033-E-CN (2007), on behalf of Steel of West Virginia, Inc., re power plant cost recovery mechanism.
53. Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership, before the Public Utilities Commission of Texas, PUC Docket No. 34077 (2007), on behalf of Nucor Steel - Texas, re acquisition of TXU Corp. by Texas Energy Future Holdings Limited Partnership.
54. Arkansas Oklahoma Gas Company, before the Arkansas Public Service Commission, Docket No. 07-026-U (2007), on behalf of West Central Arkansas Gas Consumers, re gas cost-of-service and rate design issues.
55. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-07-08 (2007), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.

56. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1056 (2007), on behalf of the General Services Administration, re demand-side management and advanced metering programs.

57. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2007-229-E (2007), on behalf of CMC Steel-SC, re cost-of-service and rate design issues.

58. Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 9092 (2007), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.

59. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1053 (2007), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.

60. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32907 (2006), on behalf of Texas Cities, re hurricane cost recovery.

61. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32710/ SOAH Docket No. 473-06-2307 (2006), on behalf of Texas Cities, re reconciliation of fuel and purchased power costs.

62. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 060001-EI (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and purchased power cost recovery.

63. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-05-0816 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.

64. PacifiCorp (dba Rocky Mountain Power), before the Utah Public Service Commission, Docket No. 06-035-21 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re rate design issues.

65. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2006-2-E (2006), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.

66. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31544/ SOAH Docket No. 473-06-0092 (2006), on behalf of Texas Cities, re transition to competition rider.

67. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-05-28 (2006), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
68. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2005), on behalf of SMI Steel-Alabama, re energy cost recovery.
69. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050001-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and capacity cost recovery.
70. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31315/ SOAH Docket No. 473-05-8446 (2005), on behalf of Texas Cities, re incremental purchased capacity cost rider.
71. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050045-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.
72. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 05-042-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re power plant purchase.
73. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 04-141-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re cost-of-service and rate design issues.
74. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 412 (2005), on behalf of Nucor Steel-Hertford, re cost-of-service and interruptible rate issues.
75. Public Service Company of Colorado, before the Colorado Public Utilities Commission, Docket No. 04S-164E (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.
76. CenterPoint Energy Houston Electric, LLC, *et al.*, before the Public Utility Commission of Texas, PUC Docket No. 29526 (2004), on behalf of the Coalition of Commercial Ratepayers, re stranded cost true-up balances.
77. PacifiCorp, before the Utah Public Service Commission, Docket No. 04-035-11 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re time-of-day rate design issues.

78. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-03-0347 (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.

79. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-03-13 (2004), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re retail cost allocation and rate design issues.

80. PacifiCorp, before the Utah Public Service Commission, Docket No. 03-2035-02 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re retail cost allocation and rate design issues.

81. Dominion Virginia Power, before the Virginia State Corporation Commission, Case No. PUE-2000-00285 (2003), on behalf of Chaparral (Virginia) Inc., re recovery of fuel costs.

82. Jersey Central Power & Light Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02080506, OAL Docket No. PUC-7894-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.

83. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02050303, OAL Docket No. PUC-5744-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.

84. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2002-223-E (2002), on behalf of SMI Steel-SC, re retail cost allocation and rate design issues.

85. Montana Power Company, before the First Judicial District Court of Montana, *Great Falls Tribune et al. v. the Montana Public Service Commission*, Cause No. CDV2001-208 (2002), on behalf of a media consortium (*Great Falls Tribune*, *Billings Gazette*, *Montana Standard*, *Helena Independent Record*, *Missoulian*, Big Sky Publishing, Inc. dba *Bozeman Daily Chronicle*, the Montana Newspaper Association, *Miles City Star*, *Livingston Enterprise*, Yellowstone Public Radio, the Associated Press, Inc., and the Montana Broadcasters Association), re public disclosure of allegedly proprietary contract information.

86. Louisville Gas & Electric *et al.*, before the Kentucky Public Service Commission, Administrative Case No. 387 (2001), on behalf of Gallatin Steel Company, re adequacy of generation and transmission capacity in Kentucky.

87. PacifiCorp, before the Utah Public Service Commission, Docket No. 01-035-01 (2001), on behalf of Nucor Steel, re retail cost allocation and rate design issues.
88. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 23640/ SOAH Docket No. 473-01-1922 (2001), on behalf of Nucor Steel, re fuel cost recovery.
89. FPL Group *et al.*, before the Federal Energy Regulatory Commission, Docket No. EC01-33-000 (2001), on behalf of Arkansas Electric Cooperative Corporation, Inc., re merger-related market power issues.
90. Entergy Mississippi, Inc., *et al.*, before the Mississippi Public Service Commission, Docket No. 2000-UA-925 (2001), on behalf of Birmingham Steel-Mississippi, re appropriate regulatory conditions for merger approval.
91. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 22350/ SOAH Docket No. 473-00-1015 (2000), on behalf of Nucor Steel, re unbundled cost of service and rates.
92. PacifiCorp, before the Utah Public Service Commission, Docket No. 99-035-10 (2000), on behalf of Nucor Steel, re using system benefit charges to fund demand-side resource investments.
93. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-190-U (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re the development of competitive electric power markets in Arkansas.
94. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-048-R (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re generic filing requirements and guidelines for market power analyses.
95. ScottishPower and PacifiCorp, before the Utah Public Service Commission, Docket No. 98-2035-04 (1999), on behalf of Nucor Steel, re merger conditions to protect the public interest.
96. Dominion Resources, Inc. and Consolidated Natural Gas Company, before the Virginia State Corporation Commission, Case No. PUA990020 (1999), on behalf of the City of Richmond, re market power and merger conditions to protect the public interest.
97. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 18465 (1998) on behalf of the Texas Commercial Customers, re excess earnings and stranded-cost recovery and mitigation.

98. PJM Interconnection, LLC, before the Federal Energy Regulatory Commission, Docket No. ER98-1384 (1998) on behalf of Wellsboro Electric Company, re pricing low-voltage distribution services.
99. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, re market power in relevant markets.
100. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070458 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.
101. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070459 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.
102. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070461 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.
103. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070462 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.
104. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, Allegheny Electric Cooperative, Inc., and Selected Municipalities, re market power in relevant markets.
105. CSW Power Marketing, Inc., before the Federal Energy Regulatory Commission, Docket No.ER97-1238-000 (1997) on behalf of the Transmission Dependent Utility Systems, re market power in relevant markets.
106. Central Hudson Gas & Electric Corporation *et al.*, before the New York Public Service Commission, Case Nos. 96-E-0891, 96-E-0897, 96-E-0898, 96-E-0900, 96-E-0909 (1997), on behalf of the Retail Council of New York, re stranded-cost recovery.
107. Central Hudson Gas & Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0909 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
108. Consolidated Edison Company of New York, Inc., supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0897 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.

109. New York State Electric & Gas Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0891 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.

110. Rochester Gas and Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0898 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.

111. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 15015 (1996), on behalf of Nucor Steel-Texas, re real-time electricity pricing.

112. Central Power and Light Company, before the Public Utility Commission of Texas, Docket No. 14965 (1996), on behalf of the Texas Retailers Association, re cost of service and rate design.

113. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 95-1076-E (1996), on behalf of Nucor Steel-Darlington, re integrated resource planning.

114. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13575 (1995), on behalf of Nucor Steel-Texas, re integrated resource planning, DSM options, and real-time pricing.

115. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Initial Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

116. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Reply Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

117. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Final Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

118. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 94-202-G (1995), on behalf of Nucor Steel, re integrated resource planning and rate caps.

119. Gulf States Utilities Company, before the United States Court of Federal Claims, *Gulf States Utilities Company v. the United States*, Docket No. 91-1118C (1994, 1995), on behalf of the United States, re electricity rate and contract dispute litigation.

120. American Electric Power Corporation, before the Federal Energy Regulatory Commission, Docket No. ER93-540-000 (1994), on behalf of DC Tie, Inc., re costing and pricing electricity transmission services.

121. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13100 (1994), on behalf of Nucor Steel-Texas, re real-time electricity pricing.

122. Carolina Power & Light Company, *et al.*, Proposed Regulation Governing the Recovery of Fuel Costs by Electric Utilities, before the South Carolina Public Service Commission, Docket No. 93-238-E (1994), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

123. Southern Natural Gas Company, before the Federal Energy Regulatory Commission, Docket No. RP93-15-000 (1993-1995), on behalf of Nucor Steel-Darlington, re costing and pricing natural gas transportation services.

124. West Penn Power Company, *et al.*, v. State Tax Department of West Virginia, *et al.*, Civil Action No. 89-C-3056 (1993), before the Circuit Court of Kanawha County, West Virginia, on behalf of the West Virginia Department of Tax and Revenue, re electricity generation tax.

125. Carolina Power & Light Company, *et al.*, Proceeding Regarding Consideration of Certain Standards Pertaining to Wholesale Power Purchases Pursuant to Section 712 of the 1992 Energy Policy Act, before the South Carolina Public Service Commission, Docket No. 92-231-E (1993), on behalf of Nucor Steel-Darlington, re Section 712 regulations.

126. Mountain Fuel Supply Company, before the Public Service Commission of Utah, Docket No. 93-057-01 (1993), on behalf of Nucor Steel-Utah, re costing and pricing retail natural gas firm, interruptible, and transportation services.

127. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 11735 (1993), on behalf of the Texas Retailers Association, re retail cost-of-service and rate design.

128. Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE920041 (1993), on behalf of Philip Morris USA, re cost of service and retail rate design.

129. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 92-209-E (1992), on behalf of Nucor Steel-Darlington.

130. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Rate Design (1992), on behalf of the Department of Energy, Strategic Petroleum Reserve.
131. Georgia Power Company, before the Georgia Public Service Commission, Docket Nos. 4091-U and 4146-U (1992), on behalf of Amicalola Electric Membership Corporation.
132. PacifiCorp, Inc., before the Federal Energy Regulatory Commission, Docket No. EC88-2-007 (1992), on behalf of Nucor Steel-Utah.
133. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 90-452-G (1991), on behalf of Nucor Steel-Darlington.
134. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 91-4-E, 1991 Fall Hearing, on behalf of Nucor Steel-Darlington.
135. Sonat, Inc., and North Carolina Natural Gas Corporation, before the North Carolina Utilities Commission, Docket No. G-21, Sub 291 (1991), on behalf of Nucor Corporation, Inc.
136. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-91-001 (1991), on behalf of North Star Steel-Minnesota.
137. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase IV-Rate Design (1991), on behalf of the Department of Energy, Strategic Petroleum Reserve.
138. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 9850 (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve.
139. General Services Administration, before the United States General Accounting Office, Contract Award Protest (1990), Solicitation No. GS-00P-AC87-91, Contract No. GS-00D-89-B5D-0032, on behalf of Satilla Rural Electric Membership Corporation, re cost of service and rate design.
140. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 90-4-E (1990 Fall Hearing), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.
141. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve, re cost of service and rate design.

142. Atlanta Gas Light Company, before the Georgia Public Service Commission, Docket No. 3923-U (1990), on behalf of Herbert G. Burris and Oglethorpe Power Corporation, re anticompetitive pricing schemes.

143. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 89-1001-EL-AIR (1990), on behalf of North Star Steel-Ohio, re cost of service and rate design.

144. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Cost of Service/Revenue Spread (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

145. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-89-865 (1989), on behalf of North Star Steel-Minnesota.

146. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

147. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 89-039-10 (1989), on behalf of Nucor Steel-Utah and Vulcraft, a division of Nucor Steel.

148. Soyland Power Cooperative, Inc. v. Central Illinois Public Service Company, Docket No. EL89-30-000 (1989), before the Federal Energy Regulatory Commission, on behalf of Soyland Power Cooperative, Inc., re wholesale contract pricing provisions

149. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 8702 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

150. Houston Lighting and Power Company, before the Public Utility Commission of Texas, Docket No. 8425 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

151. Northern Illinois Gas Company, before the Illinois Commerce Commission, Docket No. 88-0277 (1989), on behalf of the Coalition for Fair and Equitable Transportation, re retail gas transportation rates.

152. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 79-7-E, 1988 Fall Hearing, on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

153. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 869 (1988), on behalf of Peoples Drug Stores, Inc., re cost of service and rate design.

154. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 88-11-E (1988), on behalf of Nucor Steel-Darlington.

155. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GR-87-670 (1988), on behalf of the Metalcasters of Minnesota.

156. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 87-689-EL-AIR (1987), on behalf of North Star Steel-Ohio.

157. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 87-7-E (1987), on behalf of Nucor Steel-Darlington.

158. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase I (1987), on behalf of the Strategic Petroleum Reserve.

159. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 7195 (1987), on behalf of the Strategic Petroleum Reserve.

160. Gulf States Utilities Company, before the Federal Energy Regulatory Commission, Docket No. ER86-558-006 (1987), on behalf of Sam Rayburn G&T Cooperative.

161. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 85-035-06 (1986), on behalf of the U.S. Air Force.

162. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 6765 (1986), on behalf of the Strategic Petroleum Reserve.

163. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 85-212 (1986), on behalf of the U.S. Air Force.

164. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket Nos. 6477 and 6525 (1985), on behalf of North Star Steel-Texas.

165. Ohio Edison Company, before the Ohio Public Utilities Commission, Docket No. 84-1359-EL-AIR (1985), on behalf of North Star Steel-Ohio.

166. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 84-035-01 (1985), on behalf of the U.S. Air Force.

167. Central Vermont Public Service Corporation, before the Vermont Public Service Board, Docket No. 4782 (1984), on behalf of Central Vermont Public Service Corporation.

168. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-15641 (1983), on behalf of the Strategic Petroleum Reserve.
169. Southwestern Power Administration, before the Federal Energy Regulatory Commission, Rate Order SWPA-9 (1982), on behalf of the Department of Defense.
170. Public Service Company of Oklahoma, before the Federal Energy Regulatory Commission, Docket Nos. ER82-80-000 and ER82-389-000 (1982), on behalf of the Department of Defense.
171. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 80-66 (1981), on behalf of the Commission Staff.
172. Bangor Hydro-Electric Company, before the Maine Public Utilities Commission, Docket No. 80-108 (1981), on behalf of the Commission Staff.
173. Oklahoma Gas & Electric, before the Oklahoma Corporation Commission, Docket No. 27275 (1981), on behalf of the Commission Staff.
174. Green Mountain Power, before the Vermont Public Service Board, Docket No. 4418 (1980), on behalf of the PSB Staff.
175. Williams Pipe Line, before the Federal Energy Regulatory Commission, Docket No. OR79-1 (1979), on behalf of Mapco, Inc.
176. Boston Edison Company, before the Massachusetts Department of Public Utilities, Docket No. 19494 (1978), on behalf of Boston Edison Company.
177. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 173, on behalf of the Commission Staff.
178. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-100, Sub 32, on behalf of the Commission Staff.
179. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 203, on behalf of the Commission Staff.
180. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 170, on behalf of the Commission Staff.
181. Southern Bell Telephone Company, before the North Carolina Utilities Commission, Docket No. P-5, Sub 48, on behalf of the Commission Staff.
182. Western Carolina Telephone Company, before the North Carolina Utilities Commission, Docket No. P-58, Sub 93, on behalf of the Commission Staff.

183. Natural Gas Ratemaking, before the North Carolina Utilities Commission, Docket No. G-100, Sub 29, on behalf of the Commission Staff.
184. General Telephone Company of the Southeast, before the North Carolina Utilities Commission, Docket No. P-19, Sub 163, on behalf of the Commission Staff.
185. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 264, on behalf of the Commission Staff.
186. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 297, on behalf of the Commission Staff.
187. Duke Power Company, *et al.*, Investigation of Peak-Load Pricing, before the North Carolina Utilities Commission, Docket No. E-100, Sub 21, on behalf of the Commission Staff.
188. Investigation of Intrastate Long Distance Rates, before the North Carolina Utilities Commission, Docket No. P-100, Sub 45, on behalf of the Commission Staff.