CITY OF
PORTLAND, OREGON
OFFICE OF CITY ATTORNEY

Linda Meng, City Attorney
1221 S.W. 4th Avenue, Suite 430
Portland, Oregon 97204
Telephone: (503) 823-4047
Fax No.: (503) 823-3089

August 19, 2010

Public Utility Commission
Attention: Filing Center
550 Capitol Street NE #215
PO Box 2148
Salem, OR 97308

Re: Docket No. UE 215: PGE Request for a General Rate Revision

Dear Commission:

Enclosed for filing is an original and five copies of the City of Portland's Rebuttal Testimony and Exhibits COP/200-204-A, including Workpapers for COP 200 in the above-referenced docket.

Copies have been served on parties to this proceeding as identified in the attached service list in this matter.

Very truly yours,

Benjamin Walters

Benjamin Walters
Chief Deputy City Attorney

BW:lw
Enclosures
cc: Service List-UE 215

F:\atlouise.wrk\UE 215 - Ltr re COP's Rebuttal Testimony.doc

UE 215 – SERVICE LIST

JOSEPH MACDONALD
15273 SE LA BONITA WAY
OAKGROVE OR 97267

KURT J BOEHM
ATTORNEY
BOEHM KURTZ & LOWRY
36 E SEVENTH ST - SUITE 1510
CINCINNATI OH 45202
kboehm@bkllawfirm.com

GORDON FEIGHNER **(C)**
ENERGY ANALYST
CITIZENS' UTILITY BOARD OF OREGON
610 SW BROADWAY, SUITE 308
PORTLAND OR 97025
gordon@oregoncub.org

ROBERT JENKS **(C)**
EXECUTIVE DIRECTOR
CITIZENS' UTILITY BOARD OF OREGON
610 SW BROADWAY, SUITE 308
PORTLAND OR 97205
bob@oregoncub.org

G. CATRIONA MCCRACKEN **(C)**
LEGAL COUNSEL/STAFF ATTY
CITIZENS' UTILITY BOARD OF OREGON
610 SW BROADWAY - SUITE 308
PORTLAND OR 97205
catriona@oregoncub.org

RAYMOND MYERS **(C)**
ATTORNEY
CITIZENS' UTILITY BOARD OF OREGON
610 SW BROADWAY - STE 308
PORTLAND OR 97205
ray@oregoncub.org

JORDAN A WHITE
SENIOR COUNSEL
PACIFIC POWER & LIGHT
1407 W. NORTH TEMPLE, STE 320
SALT LAKE CITY UT 84116
jordan.white@pacificorp.com

JESS KINCAID
COMMUNITY ACTION PARTNERSHIP OF OREGON
PO BOX 7964
SALEM OR 97301
jess@caporegon.org

KEVIN ELLIOTT PARKS **(C)**
CITIZENS' UTILITY BOARD OF OREGON
610 SW BROADWAY - STE 308
PORTLAND OR 97205
kevin@oregoncub.org

S BRADLEY VAN CLEVE **(C)**
DAVISON VAN CLEVE PC
333 SW TAYLOR - SUITE 400
PORTLAND OR 97204
mail@dvclaw.com

STEPHANIE S ANDRUS **(C)**
ASSISTANT ATTORNEY GENERAL
DEPARTMENT OF JUSTICE
REGULATED UTILITY & BUSINESS SECTION
1162 COURT ST NE
SALEM OR 97301-4096
stephanie.andrus@state.or.us

KEVIN HIGGINS
PRINCIPLE
ENERGY STRATEGIES LLC
215 STATE ST - SUITE 200
SALT LAKE UT 84111-2322
khiggins@energystrat.com

NONA SOLTERO
CORPORATE LAW DEPT #23C
FRED MEYER STORES/KROGER
3800 SE 22ND AVE
PORTLAND OR 97202
nona.soltero@fredmeyer.com

PACIFICORP, DBA PACIFIC POWER
OREGON DOCKETS
825 NE MULTNOMAH ST, STE 2000
PORTLAND OR 97232
oregondockets@pacificorp.com

RANDALL DAHLGREN
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST - 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com

DOUGLAS C TINGEY **(C)**
PORTLAND GENERAL ELECTRIC
121 SW SALMON 1WTC13
PORTLAND OR 97204
doug.tingey@pgn.com

JUDY JOHNSON **(C)**
PUBLIC UTILITY COMMISSION
PO BOX 2148
SALEM OR 97308-2148
judy.johnson@state.or.us

MARCIA L. PUTMAN
IBEW LOCAL 125
17200 NE SACRAMENTO ST.
PORTLAND OR 97230
marcy@ibew125.com

RANDALL J. FALKENBERG **(C)**
RFI CONSULTING INC.
PMB 362
8343 ROSWELL RD
SANDY SPRINGS GA 30350
consultrfi@aol.com

PETER J. RICHARDSON (C)
RICHARDSON & O'LEARY PLLC
PO BOX 7218
BOISE ID. 83707
peter@richardsonandoleary.com

LEO SMITH
THE INTERNATIONAL DARK SKY ASSN.
1060 MAPLETON AVE
SUFFIELD CT 06078
leo@smith.net

GREGORY M. ADAMS
RICHARDSON & O'LEARY
PO Box 7218
BOISE ID 83702
greg@richardsonandoleary.com

GREG BASS
SEMPRA ENERGY SOLUTIONS LLC
401 WEST A STREET, SUITE 500
SAN DIEGO CA 92101
gbass@semprasolutions.com

HEATHER RODE
21465 NW COFFEY LANE
HILLSBORO OR 97124
heatherrode@gmail.com

LON L. PETERS
NORTHWEST ECONOMIC RESEARCH INC.
607 SE MANCHESTER PLACE
PORTLAND OR 97205
lon@nw-econ.com

DAVID TOOZE
CITY OF PORTLAND-
PLANNING & SUSTAINABILITY
1900 SW 4TH, SUITE 7100
PORTLAND OR 97201
david.tooze@portlandoregon.gov

JAMES BENYA
THE INTERNATIONAL DARK
SKY ASSOCIATION
3491 CASCADE TERRRACE
WEST LINN OR 97068
jbenya@benyalighting.com

UE 215
Exhibit COP/200
Witnesses: Gray, Koonce, Nierengarten, and Peters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

CITY OF PORTLAND

Rebuttal Testimony of Richard Gray, Peter Koonce, Peter Nierengarten and Lon L. Peters

Rate Design
Schedules 32, 83, 85, 89 and 91
Customer Impact Offset

August 2010

Q. PLEASE STATE YOUR NAMES.

A. My name is Richard Gray.

A. My name is Peter Koonce.

A. My name is Peter Nierengarten.

A. My name is Lon L. Peters.

A. [All] We have previously sponsored Exhibits COP/100 through COP/108 in this proceeding.

Q. WHAT ARE THE PURPOSES OF THIS REBUTTAL TESTIMONY?

A. The purposes of this rebuttal testimony are (i) to address arguments made in PGE/2100 and (ii) to propose a specific transition to improved design for rate schedules with demand charges.

Q. DOES THE CITY AGREE WITH THE STIPULATIONS ALREADY FILED IN THIS PROCEEDING?

A. For the most part, yes. The City has elected not to endorse these stipulations for one basic reason: although PGE's customers will be better off in the short-run due to reductions in the company's overall revenue requirement, we question the wisdom of cutting AMI implementation expenses in 2011. The first revenue requirement stipulation, filed on July 1, 2010 includes a $1.7 million AMI expense reduction. We suspect that this stipulated expense reduction reinforces PGE's decision not to redesign rates using AMI capabilities for an indeterminate period. Given (a) the substantial new capacity costs (generation and transmission) that PGE expects to incur, (b) the decision already made by the Commission to include AMI investments in rate base, and (c) the inadequate incentives and, in some cases, actual disincentives in PGE's rate schedules for peak demand reductions and load shifting, we recommend that the Commission review this one line item of the stipulation and consider instating a level of expenses in 2011 that will permit more rapid innovation in rate design than is implicit in PGE's rebuttal testimony. We do not have a specific dollar amount of expenses that should be reinstated, and recommend that the Commission direct PGE to work with intervenors to establish the amount required in order to accomplish the transition to an improved rate design by January 1, 2012.

I. Improvements in Rate Design

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. The purpose of this section is to address those arguments in PGE/2100 against a rate design that better reflects PGE's short-run and long-run marginal costs of generation and transmission capacity.

Q. DID THE CITY PROPOSE A GENERATION DEMAND CHARGE IN COP/100?

A. As PGE has correctly stated, the City did not explicitly propose a *separate* generation demand charge. PGE/2100, Kuns/Cody, 6. The City did not propose a *separate* generation demand charge because of a recognition that changes in billing practices are difficult. Adding a new demand charge could exacerbate difficulties that PGE already faces in managing the transition to AMI billing. See PGE Response to COP Data Request 039(c), attached here as Exhibit COP/201. Therefore, the City proposed increasing *existing* demand charges to achieve the desired effect: a greater incentive to reduce peak loads. If a *separate* generation demand charge is required to meet other PGE rate design objectives, the City would not object in concept. The point is not "how many demand charges are there?" but "what is the total incentive to shift or reduce peak load?" A separate generation demand charge could address PGE's concerns about shifts in cost recovery among small and large customers within a given rate schedule, and would allow transmission and distribution demand charges to be kept separate from generation demand charges.

Q. DO OTHER UTILITIES HAVE SEPARATE GENERATION DEMAND CHARGES?

A. Yes. The following utilities currently have, or have proposed, separate generation demand or generation capacity charges, in some cases seasonally differentiated: Public Service Colorado (CO), Fredericksburg (TX), Tucson Electric (AZ), Virginia Electric and Power Company (VA), Wheatbelt Public Power District (NE), and Wyrulec (WY).

Q. WHY DOES THE CITY CONSIDER A GENERATION DEMAND CHARGE, EITHER SEPARATE OR NOT, TO BE IMPORTANT?

A. The City accepts PGE's estimate that the company's long-run marginal cost of generation capacity is more than $190/kW-year (PGE/1500, Kuns/Cody, 4), although this is somewhat higher than the estimates for gas-fired capacity resources built by investor-owned utilities in the *Sixth Northwest Conservation and Electric Power Plan*, (Table 6-1) issued earlier this year by the Northwest Power and Conservation Council. (See Council Document 2010-09, at www.nwcouncil.org/energy/powerplan/6/default.htm.) Because this long-run cost is so high, relative to current and proposed demand charges, it is important that PGE's rate design be modified. Using the long-run cost of capacity solely to allocate embedded costs is insufficient.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE OF THE INADEQUACY OF THE PROPOSED RATE DESIGN?

A. Yes. Consider a Schedule 89 customer taking service at secondary voltage. If that customer reduced its peak period demand by one kW every month for an entire year, the customer would save about $70 in demand charges under PGE's initial proposal in 2011. In comparison, this load reduction would cut PGE's long-run marginal costs of generation and transmission capacity by about $250 per year. See Exhibit COP/202. Even taking into account the need to discount the long-run marginal costs back to 2011 for comparability, the individual customer in this simple example would receive a fraction of the system-wide savings in capacity costs. In some cases, e.g., the City's Water Bureau, the savings to the customer would in fact be negative, which means that peak load reductions will not occur even though all customers would benefit. We conclude that the proposed rate design does not provide correct price signals for demand reductions.

Q. PLEASE ADDRESS PGE'S CONCERN ABOUT NEGATIVE INFRAMARGINAL DEMAND CHARGES (PGE/2100, KUNS/CODY, 6, 19).

A. The City recognizes that increasing the proposed Demand Charges, all tied to distribution and transmission costs, could generate incremental revenues that would have to be credited somewhere in order to preserve "revenue neutrality". Again, for simplicity, revenue neutrality, and the preservation of the marginal demand price signal, the City proposed in COP/100 that these incremental revenues be returned to the inframarginal demand blocks. However, other revenue crediting mechanisms are possible that would preserve the marginal demand price signal. For example, the additional revenues could reduce the off-peak energy charge within the same rate schedule, or could reduce some other infra-marginal charge.

Q. PLEASE ADDRESS THE ARGUMENT THAT THE CITY INTENDED TO SHIFT COST RESPONSIBILITY BETWEEN SMALL AND LARGE CUSTOMERS WITHIN A GIVEN RATE SCHEDULE (PGE/2100, KUNS/CODY, 6, 18).

A. The City's intent was *not* to transfer cost responsibility from smaller to larger customers within a given rate schedule, but to present all customers with the same marginal-cost-based demand charge.

Q. PLEASE ADDRESS THE ARGUMENT THAT THE CITY "CREATED" A PROBLEM WHERE NONE EXISTS (PGE/2100, KUNS/CODY, 7).

A. The City did not create the problem. The problem is created by the proposal to use marginal costs only to *allocate* embedded costs, not to create *incentives*, via marginal demand charges, for individual customers to make changes that would save *all* customers money in the long run.

Q. DOES THE CITY OBJECT TO ENERGY PRICE DIFFERENTIALS IN SCHEDULE 32 (PGE/2100, KUNS/CODY, 7 AND 14)?

A. No. The City does not object to "large peak period differentials" in Schedule 32, but merely points out that they are, as PGE describes them, "purposely exaggerate[d]": not based on estimates or projections of marginal or embedded costs. The City agrees that purposely exaggerated diurnal price differentials will increase the incentive to shift load. However, without a basis in avoided, marginal, fixed or embedded costs, the impact of load shifts on other customers is hard to judge. For example, if the "exaggerated" peak period energy prices are higher than PGE's short-run avoidable peak period energy costs, then load shifting by individual Schedule 32 customers would cause fixed costs to be recovered from other customers.

Q. PGE POINTS TO MARKET-BASED MONTHLY AND DAILY ENERGY PRICE OPTIONS AS MEANS TO THE END SOUGHT BY THE CITY (PGE/2100, KUNS/CODY, 8 AND 17). WHAT IS YOUR RESPONSE?

A. PGE's market-based monthly and daily price energy options, and purchases from ESSs, are not realistic options for the City, because of the risks relative to the potential savings. Despite years of effort, the uncertainties and complications associated with transactions with ESSs have been sufficient to terminate attempts to acquire wind generation to serve the City's loads. PGE can offer diurnally differentiated energy prices based on PGE's understanding of forward market conditions with much greater certainty than can the City, including forward purchases, and it is therefore appropriate and reasonable for PGE to offer such prices. The indisputable facts are (1) forward diurnally and monthly differentiated energy markets exist for 2011, and (2) PGE relies on these markets. We are only asking PGE to pass through these diurnal (and monthly or seasonal) price differentials directly to customers, rather than muting them.

Q. PLEASE ADDRESS PGE'S ARGUMENT THAT ADDITIONAL TIME-OF-USE RATE DESIGNS BE POSTPONED (PGE/2100, KUNS/CODY, 8 AND 13).

A. PGE's proposal in this case is to (a) complete the installation of the AMI system in 2010 while (b) cutting its proposed AMI implementation budget in 2011. This is a classic example of what economists identified about fifty years ago, known as the "Averch-Johnson effect": the capital costs of AMI are going into rate base, thus generating a return to PGE's shareholders, but many of the potential benefits of AMI to the ratepayers in the long run are postponed, perhaps indefinitely, because of a desire to cut expenses in the near term. The Commission should consider rejecting that part of the stipulation that reduces AMI implementation budgets, and require PGE to adopt a fixed schedule for changes in rate design so that all ratepayers can benefit in both the short- and long-run.

Q. DID THE CITY PROPOSE "BLIND" APPLICATION OF FIXED RECOVERY PERCENTAGES FOR BASIC CHARGES (PGE/2100, KUNS/CODY, 8)?

A. No. The City did not propose "blind" application of fixed recovery percentages for Basic Charges. Rather, the City used PGE's proposed rate design to demonstrate that the relationship between proposed Basic Charges and underlying customer-related costs varies significantly across rate schedules, which raises the question of how the charges are (or are not) connected to PGE's underlying costs, whether those costs are defined as embedded or marginal.

Q. PLEASE ADDRESS THE ISSUE OF WITHIN-RATE-SCHEDULE SUBSIDIES (PGE/2100, KUNS/CODY, 9).

A. PGE has described the rate design stipulation of late July 2010 as the source of subsidies for smaller Schedule 85 customers at the expense of larger 85 customers. See PGE Response to COP Data Request 048, attached here as Exhibit COP/203. This suggests that some subsidies are acceptable, but others are not. A policy decision on the scope and nature of appropriate subsidies is clearly before the Commission, especially where those subsidies are used to argue against marginal-cost rate design. If the appropriate rate design creates significant bill impacts, those can be addressed without disturbing charges tied to marginal costs.

Q. DO YOU DISAGREE WITH PGE'S ARGUMENTS ABOUT ECONOMIES OF SCALE IN THE DISTRIBUTION FUNCTION (PGE/2100, KUNS/CODY, 10)?

A. No. PGE's documentation implies declining marginal costs for distribution as customer size increases. However, in COP/100 we recommended increasing the distribution demand charges *only* to avoid the changes to billing procedures that a new demand charge would require. With a separate generation demand charge, PGE's declining marginal costs for distribution could still be reflected in declining block distribution demand charges, where those reflect PGE's underlying cost structure.

Q. PLEASE ADDRESS PGE'S ARGUMENT THAT THE CITY HAS MADE ERRONEOUS STATEMENTS ABOUT DEMAND BILLING FACTORS FOR SCHEDULES 85 AND 89 (PGE/2100, KUNS/CODY, 11).

A. The City's "erroneous" statements about the demand billing factors for Schedules 85 and 89 were based on statements by PGE staff as well as a review of Rule B. To avoid such confusion in future, Rule B should include an explicit definition of On-Peak Demand, which is missing even though On-Peak Demand appears to be a defined term in the rate schedules.

Q. WOULD HIGHER DEMAND CHARGES NECESSARILY CAUSE LOWER VOLUMETRIC CHARGES AND THUS INTERFERE WITH INCENTIVES TO CONSERVE (PGE/2100, KUNS/CODY, 11)?

A. No. PGE asserts that higher demand charges would require lower volumetric charges and that this would reduce the incentive to conserve. This conclusion would be accurate if the additional revenues from higher demand charges were used *only* to reduce *marginal* volumetric charges. Additional revenues do not have to reduce the incentive to conserve, depending on how the credit is structured. As long as the credits reduce inframarginal charges (demand or energy) or fixed (unavoidable) charges, the incentive to conserve energy can and should be preserved.

Q. SHOULD THE COMMISSION BE CONCERNED ABOUT THE INCENTIVES TO CONSERVE BOTH ENERGY AND CAPACITY?

A. Yes. PGE argues that the company has proposed "higher volumetric energy charges", which provide a "strong incentive" for energy efficient behavior. (See PGE/2100, Kuns/Cody, 12-13.) This misses the point of COP/100. Energy efficiency is an important objective, but avoiding or postponing peak demand costs is another. As demonstrated above, PGE's rate design provides inadequate incentives to reduce peak demand. Also, the City did not argue for "higher fixed charges". The City argued for higher marginal demand charges, which are not always fixed but can, in some cases, be avoided by customers taking action to shift load.

Q. IS THE CITY'S PROPOSAL REGARDING DEMAND CHARGES DISCRIMINATORY WITHIN SCHEDULE 89 (PGE/2100, KUNS/CODY, 12, 19)?

A. No. The City proposed that all marginal demand charges be the same for all customers on Schedule 89 (i.e., all customers already over one MW). By itself, this is not discriminatory. The potential for a "discriminatory" result depends on the nature of the required revenue credit, among other things.

Q. PLEASE ADDRESS PGE'S ARGUMENTS REGARDING "MIGRATION" ACROSS RATE SCHEDULES (PGE/2100, KUNS/CODY, 15-17).

A. First, the City has not implied that customers should remain on "lower" rate schedules. Second, PGE observes, correctly, that customer "migrate" both up and down across rate schedules. However, downward migration only occurs if *peak demand* falls, and yet PGE objects to the City's proposal for increased incentives to reduce peak demand. Third, the City agrees that customers should not be shocked by changes in bills when shifting across rate schedules, but objects to the use of rate design, rather than information, to achieve this objective. However, what PGE describes as "warnings and alarms" is information that the City considers should be available to the consumer. Again, the argument that providing such information to customers requires an unacceptable level of manual intervention is more evidence of the Averch-Johnson effect.

Q. HAS PGE PROVIDED ANY INFORMATION ABOUT THE COST OF PROVIDING THE RECOMMENDED INFORMATION TO CUSTOMERS?

A. Yes. PGE has estimated that the company would save costs of 1.5 to 2 Full Time Equivalent personnel by *not* providing information to consumers about billing structures. See PGE Response to City of Portland Data Request 039(e), attached here as Exhibit COP/201. Again, we do not understand the economic logic behind this particular trade-off.

Q. DO YOU DISAGREE WITH THE IDEA THAT SOME DEMAND CHARGES SHOULD BE ASSESSED 24 HOURS PER DAY (PGE/2100, KUNS/CODY, 17)?

A. In general, no. However, the Facility Capacity and Basic Charges should be assessed 24 hours a day *only if* PGE adopts a peak-period generation demand charge for all rate schedules with demand charges that provides an adequate incentive to shift or reduce peak load. We have provided above a comparison of current avoidable demand charges and PGE's long-run marginal costs of capacity. Again, the issue is not how many demand charges there are, but how the incentives to shift and reduce peak load are tied to PGE's marginal costs.

Q. WOULD NEGATIVE INFRAMARGINAL DEMAND CHARGES CREATE AN INCENTIVE TO "BREAK UP" LOAD (PGE/2100, KUNS/CODY, 19)?

A. Not necessarily. PGE believes that negative inframarginal demand charges would create an incentive to "break up" load. The City agrees that this would be a perverse result. However, if the load were broken up just to get access to negative demand charges below one MW, the loads would no longer individually qualify for Schedule 89, and the incentive would disappear. Again, negative inframarginal demand charges are not the only option for crediting revenues from higher marginal demand charges, as discussed above.

Q. PLEASE ADDRESS THE ARGUMENT THAT SEASONALLY-DIFFERENTIATED CHARGES WOULD "CONFUSE" PGE'S CUSTOMERS (PGE/2100, KUNS/CODY, 20)?

A. The City does not understand why Oregon consumers should be more easily confused than consumers in the following states, where utilities have adopted seasonally-differentiated charges, in some cases several years ago: Arizona, California, Colorado, Florida, Illinois, Kansas, Nevada, New Jersey, Pennsylvania, Texas, Utah, and Wyoming.

Q. HAS PGE PROVIDED ANY OTHER REASON FOR NOT ADOPTING DEMAND AND ENERGY PRICES THAT VARY SEASONALLY?

A. Yes. PGE has estimated that it would require 600 labor hours (i.e., one person working full-time for 15 weeks) to restructure its rates to reflect seasonal variations in near-term marginal costs. See PGE Response to COP Data Request 039(f), attached here as Exhibit COP/201. Again, we do not understand the economic logic of this particular trade-off, and can only conclude that the incentives in the Averch-Johnson effect have led to this particular conclusion.

II. Redesign of Schedules 32, 83, 85 and 89

Q. WHAT DO YOU PROPOSE AT THIS POINT IN THE PROCEEDING?

A. Given the stipulations already filed and the apparent disinterest of all other parties in engaging in discussions regarding rate redesign, the City proposes that the Commission (a) set aside that part of the stipulation that reduces AMI expenses; (b) require PGE to develop a new budget for AMI implementation in 2011 that would support a separate generation demand charge, revenue credits that do not create perverse incentives, additional time-of-use charges, and seasonally-differentiated demand and energy charges; and (c) require PGE to have all systems in place for actual implementation of a new rate design by January 1, 2012. In order to enhance the feasibility of this proposal, this deadline would apply only to those rate schedules with demand charges.

Q. SHOULD THIS RECOMMENDATION BE CONNECTED TO THE EXTERNAL REVIEW OF PGE'S DECOUPLING MECHANISM AGREED TO IN THE MOST RECENT STIPULATION?

A. No, because that review is not scheduled for 2011. Changes to decoupling required for rate redesign should be considered during 2011.

III. Schedule 91

Q. PLEASE ADDRESS PGE'S ARGUMENTS REGARDING NEW LAMP CODES IN SCHEDULE 91 (PGE/2100, KUNS/CODY, 23).

A. First, although Advice Filing 10-11 is separately docketed, the City agrees with PGE's proposal for new lamp codes in that docket. Second, the City withdraws its proposal for "obsolete lamp codes", in recognition that codes must be maintained for obsolete lamps that are still in service. Third, the City is willing to assign an individual responsible for self-reporting of lamp codes, and proposes that if any Schedule 91 customer is willing to identify such an individual, self-reporting should remain an option. Self-reporting should be subject to reasonable conditions, to simplify PGE's verification of self-reported information. We expect that this would include the development of a lamp database (using standard software such as Access), connection of the lamp database to the municipal GIS database, creation of an interface to add and delete light types, generation of a monthly report, and transmission of the report electronically to PGE, which may be interested in other functionalities. Customers who have the ability to self-report should be allowed to do so. This would extend the life of PGE's lamp code system.

Q. WHY DID THE CITY PROPOSE A BILLING CREDIT TO ADDRESS ITS CONCERNS ABOUT THE PROPER RECOVERY OF THE COSTS OF CIRCUITS (PGE/2100, KUNS/CODY, 25)?

A. For streetlight circuits, the City proposed the billing credit because it seemed to be the simplest method. The City did not propose a method for recovering the billing credit because it did not want to limit that element of rate design. The City is simply seeking a mechanism that better matches costs of service to customers taking the service.

Q. PLEASE ADDRESS PGE'S ARGUMENTS ABOUT THE INTERACTION BETWEEN THE LINE EXTENSION ALLOWANCE (LEA) AND THE ALLOCATION OF STREETLIGHT CIRCUIT COSTS (PGE/2100, KUNS/CODY, 26).

A. As we understand the position, PGE argues that the LEA has already directly assigned circuit costs to some Schedule 91 customers, and that reducing the share of circuit costs paid for by the City would run the risk that other Schedule 91 customers would pay for circuits in advance, via historical application of the LEA, and then again, via the future circuit charge. In support of this argument, PGE cites the reduction in the LEA in February 2003 by about half. However, this LEA reduction means that Account 373-1 is currently *larger* than it would have been, had the lower LEA been in effect *before* early 2003. This means that the City is paying *now* for costs in Account 373-1 that are the result of the pre-2003 LEA. Assuming that the reduction in LEA in 2003 was good public policy, the current circuit charge includes costs that *should have been* directly assigned, but were not because the LEA was "too high", at least as determined in 2003.

Q. HAS PGE PROVIDED ANY OTHER DATA THAT IS PERTINENT TO THIS ISSUE?

A. Yes. In response to COP Data Request 050, PGE has provided the number of circuit miles and circuit spans by municipality. Although this information has limitations, it can provide the basis for an allocation of circuit costs across municipalities that more closely follows cost causation than PGE's current approach. See Exhibits COP/204 and COP/204-A. Thus, the City stands behind its conclusion that the share of circuit costs paid by the City is too high.

Q. DO YOU AGREE WITH PGE'S ARGUMENT THAT ITS RATE SCHEDULES DO NOT PERMIT GEOGRAPHICAL DIFFERENTIATION OF PRICES OR CHARGES (PGE/2100, KUNS/CODY, 26)?

A. PGE states that there is no geographical differentiation of prices in any rate schedules. Although the actual language of the individual rate schedules may not include geographical distinctions, the implementation of the rate schedules taken as a whole leads to such distinctions. For example, Schedule 92 is available only to (a) governmental agencies (b) taking service as of 9/30/01 that have (c) at least 50 intersections. This means that certain municipalities (which are defined by geographical characteristics, among other things) are precluded from Schedule 92. This is a form of effective geographical differentiation *across* rate schedules. The lack of geographical differentiation *within* a rate schedule is a distinction without a difference.

Q. IS THE CITY ACTUALLY REQUESTING "GEOGRAPHICAL DIFFERENTIATION"?

A. We do not see this issue as one of geographical differentiation, but of cost causation. The City is asking to be charged for the facilities it actually uses, and for others to pay for the facilities they actually use. This is directly analogous to the LEA, because some customers have been and are required by PGE under the LEA to pay individually for specific facilities that they actually use, *and that others do not use*. One might argue that the LEA is a form of geographical price differentiation within *every* rate schedule. If the LEA in general is reasonable, then the City's proposal on circuit charges is also reasonable.

Q. SHOULD THE ASSUMED COSTS OF STREETLIGHT MAINTENANCE BE REDUCED (PGE/2100, KUNS/CODY, 27)?

A. Yes. Numerous stipulations have reduced PGE's proposed budgets in a wide variety of areas, and there seems no reason why the maintenance budget should be singularly immune. The City stands by its direct testimony on this issue.

IV. Customer Impact Offset

Q. PLEASE ADDRESS PGE'S ARGUMENTS REGARDING THE CIO (PGE/2100, KUNS/CODY, 30).

A. The City proposed reconsideration of the CIO because it has eclipsed more substantive issues. In PGE's initial proposal, the CIO was responsible for the reallocation of less than $15 million of costs or revenues in 2011, out of a total revenue requirement of about $1.8 billion. (These amounts have changed somewhat due to stipulations.) The CIO is thus less than one percent of PGE's annual revenue requirement. Broader public policy issues, including the extent to which advanced metering capabilities can be used to save future costs, should not be neglected or postponed because attention is focused on a very small portion of the total revenue requirement. If rate design changes based on AMI capabilities could save 60 MW of peak load per year, the total savings to all PGE ratepayers in the long-run could equal $15 million per year. See Exhibit COP/202.

V. Summary

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. Rate redesign to make use of AMI capabilities and encourage capacity and energy efficiency should not be put on an indefinite schedule for implementation. The Commission should require PGE to follow the lead of other utilities, and do so on a fixed schedule.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

July 19, 2010

TO: Benjamin Walters
Office of City Attorney

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to City of Portland Data Request
Dated July 02, 2010
Question No. 039

Request:

Please provide an estimate of the labor hours (including separate estimates for PGE staff and consultants) required to implement each of the following changes in rate design:

a) Addition of optional or mandatory time-of-use energy charges to Schedule 83
b) Elimination of all off-peak demand charges
c) Shift to an increasing block demand charge structure
d) Modification of Schedule 123 to incorporate rate design changes
e) Provision of information to customers associated with the transition between rate schedules, as proposed in COP/1OO
f) Seasonality of demand and energy charges

Response:
PGE objects to this Request on the basis that it is overly broad and unduly burdensome and asks for new studies not previously performed by PGE. Without waiving its objection, PGE responds as follows:

a) PGE currently has voluntary time-of-use pricing for Schedule 83 through its monthly and daily price options. PGE previously provided an estimate of the requirements to implement TOU pricing for all Schedule 83 customers in Response to COP Data Request No. 28.

b) PGE presumes that this portion of the request relates to Distribution Facilities Capacity Charges as well as the Transmission and Distribution Demand Charges for Schedules 83, 85, and 89. PGE has not performed a specific analysis regarding this COP proposal; however, CIS Billing estimates that it would require significant changes to the billing system that could not be ready for January 2011. This COP proposal would also require reassignment of personnel currently working on AMI implementation, thereby negatively impacting this important project.

c) The COP proposal to have increasing block demand charges for applicable nonresidential schedules should have no appreciable increase in labor hours to implement presuming that there is no change in the number of charges or their definitions. Should there be additional demand charges or structural changes, additional labor hours would be required. In addition, please see the response to part b) of this request.

d) PGE has not prepared labor estimates. The COP proposal is not sufficiently specified to perform meaningful estimates.

e) PGE has not prepared detailed estimates, but does believe that the bill comparisons for the second and third "Demand Events" would be a manual process. PGE estimates that the creation of manual bills and manual letters would require the addition of 1.5 to 2 Full Time Equivalent (FTE) personnel.

f) PGE estimates that it would require about 600 labor hours to build and test price changes in the billing system on all impacted schedules. Building and testing these changes would require reassignment of labor currently assigned to the AMI project, again potentially negatively impacting this important project. Additional concerns include the increase in overnight batch processing that may impact the availability of the CIS system in the mornings for Customer Service Representatives (CSRs). The prorated bills each cycle month likely would increase the number of calls to the CSRs and the amount of time needed to explain these prorated bills.

Schedule 89 (Secondary) Peak Period Demand Charges

Transmission	$	0.88	kW-mo.
Distribution	$	2.05	kW-mo.
Total	$	2.93	kW-mo.
Annual	$	70.32	kW-year

PGE's Long-Run Marginal Cost of Capacity

Generation	$	191.18	kW-year
Transmission	$	62.54	kW-year
Total	$	253.72	kW-year
Demand Charges/LRMC		28%	

Calculation of LRMC of Transmission

Project		Capital Exp. ('000,000)	Peak (MW)
South of Allston	$	45.00	381
Cascade Crossing	$	822.70	1,700
Totals	$	867.70	2,081
Fixed Charge Rate		15%	assumed
Annual cost	$	130.16	per year
Annual cost/kW	$	62.54	

CIO vs. LRMC

CIO Revenues	$	15,000,000	per year
LRMC (capacity)	$	253,724	per MW-year
CIO Revenues/LRMC		59	MW

UE 215
COP/203

August 2, 2010

TO: Benjamin Walters
Office of City Attorney

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to City of Portland Data Request
Dated July 22, 2010
Question No. 048

Request:

PGE/2100, Kuns-Cody/9, lines 17-19. Please provide the definition of "subsidy" as it is used in the conclusion that the stipulation "has the effect of subsidizing the smaller Schedule 85 customers at the expense of the larger Schedule 85 customer," and provide any analysis of the size of such subsidies.

Response:

The term "subsidizing" refers to the fact that as a result of the stipulation, smaller Schedule 85 customers will see a lower monthly bill and larger Schedule 85 customers will see a higher monthly bill because the stipulated Schedule 85 Basic Charges recover less than the full amount of customer-related costs, and the revenue decrement is spread to all Schedule 85 customers in the manner described in the UE 215 ratespread/rate design stipulation. PGE has not explicitly measured the amount of the subsidization because it is a general statement; the degree of the subsidizing is dependent on each individual Schedule 85 customer's unique usage characteristics.

August 3, 2010

TO: Benjamin Walters
Office of City Attorney

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to City of Portland Data Request
Dated July 22, 2010
Question No. 050

Request:

PGE/2100, Kuns-Cody/26. Please provide the number of streetlight circuit miles and streetlight circuit counts for each Schedule 91 customer, with customer names masked or redacted if necessary

Response:

PGE objects to this request as overly broad and unduly burdensome and seeking information that is not relevant or reasonably calculated to lead to the discovery of admissible information. Without waiving its objection PGE responds as follows:

PGE does not catalog streetlight circuits in the manner requested. Attachment 050-A however, provides streetlight circuit miles contained within municipalities for which PGE is able to obtain data. In many cases, PGE is unable to associate wire mile data with a particular Schedule 91 customer within its unincorporated areas. In addition, the wire mile data that is within each municipality does not necessarily mean that the municipality is the customer per se; in some cases, a state or county entity may be the customer within the municipality. Circuit spans after the year 2000 correspond to pole-to-pole bases. However circuit spans installed prior to the year 2000 may have several pole-to-pole spans counted as one.

UE 215
Attachment 050-A

Streetlight Circuit Miles Contained Within Municipalities

STL Circuit Miles	Circuit Spans	Municipality Code
1.21	34	1
1.57	67	2
2.37	74	3
0.06	2	4
142.54	3,972	5
1.67	93	6
18.98	698	7
13.29	542	8
2.39	79	9
1.23	51	10
4.35	191	11
2.43	69	12
7.73	296	13
19.75	784	14
0.75	26	15
2.85	106	16
10.14	371	17
189.37	6,471	18
54.61	2,846	19
169.92	5,912	20
2.53	131	21
0.13	2	22
32.66	1,178	23
4.33	202	24
4.90	282	25
63.77	1,666	26
0.08	1	27
28.27	738	28
10.97	456	29
2.59	123	30
28.87	1,261	31
3.44	124	32
57.80	2,326	33
412.51	11,648	34
0.09	2	35
187.44	6,628	36
18.75	1,011	37
0.34	18	38
4.31	153	39
41.88	1,492	40
12.24	586	41
0.09	3	42
0.48	17	43
98.14	3,055	44
36.83	1,282	45
68.69	2,235	46
2.66	121	47
502.70	18,184	Unincorporated
49.46	1,612	48
4.06	106	49
56.97	1,626	50
8.33	360	51
31.72	1,292	52
1.01	63	53
		54
2,426.25	82,668	55

WORKPAPERS FOR

COP/200

FILED
PUBLIC SERVICE COMMISSION
OF WYOMING

DEC 2 2 2008

Carbon Power & Light, Inc.
100 E. Willow Street
P.O. Box 579
Saratoga, Wyoming 82331-0579

Wyoming PSC No. 4

First Revised Sheet No. 22
Cancels Original Revised Sheet No. 22

DEMAND AND ENERGY CHARGES

Rate Code & Name	*Billing Units*	*Rate*
A – General Service	All kWh	$0.10260
A-S – General Service Seasonal	All kWh	$0.10260
A-TOD – General Time-of-Day	Winter: On-Peak	$0.11090
	Winter: Off-Peak	$0.05190
	Summer: All kWh	$0.10260
LP – Large Power	All kWh	$0.04140
	All kW	$ 23.50
I – Irrigation	All kWh	$0.08000
	All kW	$ 16.50
OL – Outdoor Lighting	100 Watt	$ 10.00
	250 Watt	$ 18.75
	100 Watt Shielded	$ 10.50
	250 Watt Shielded	$ 19.25
Net Metering-Avoided Cost	All kWh	$0.02150
PV – Photovoltaic	Module Charge	$0.10260

Date Issued December 15, 2008

Date Effective January 1, 2009

By

Title General Manager

PURCHASED ELECTRICITY CHARGES

Supplement to Rate BES and Rider PE (1)

Customer Group or Subgroup	Units	Purchased Electricity Charges (PECs) Applicable for Service Provided Beginning with the April 2010 Monthly Billing Period and Extending Through the May 2010 Monthly Billing Period (2) (3)	
		Summer PEC	Nonsummer PEC
Residential Non-Electric Space Heating	¢/kWh	6.635	6.480
Residential Electric Space Heating	¢/kWh	5.277	4.006
Watt-hour Non-Electric Space Heating	¢/kWh	6.770	6.580
Demand Non-Electric Space Heating	¢/kWh	6.675	6.536
Nonresidential Electric Space Heating	¢/kWh	6.365	6.261
Dusk to Dawn Lighting	¢/kWh	2.431	2.905
General Lighting	¢/kWh	6.351	6.331

Customer Group or Subgroup	Units	PECs Applicable for Service Provided Beginning with the June 2010 Monthly Billing Period and Extending Through the December 2010 Monthly Billing Period (2) (3)	
		Summer PEC	Nonsummer PEC
Residential Non-Electric Space Heating	¢/kWh	7.837	7.653
Residential Electric Space Heating	¢/kWh	6.233	4.731
Watt-hour Non-Electric Space Heating	¢/kWh	7.953	7.730
Demand Non-Electric Space Heating	¢/kWh	7.842	7.679
Nonresidential Electric Space Heating	¢/kWh	7.478	7.357
Dusk to Dawn Lighting	¢/kWh	2.844	3.398
General Lighting	¢/kWh	7.430	7.407

Customer Group or Subgroup	Units	PECs Applicable for Service Provided Beginning with the January 2011 Monthly Billing Period and Extending Through the May 2011 Monthly Billing Period (2) (3)	
		Summer PEC	Nonsummer PEC
Residential Non-Electric Space Heating	¢/kWh	7.782	7.600
Residential Electric Space Heating	¢/kWh	6.190	4.698
Watt-hour Non-Electric Space Heating	¢/kWh	7.919	7.696
Demand Non-Electric Space Heating	¢/kWh	7.808	7.645
Nonresidential Electric Space Heating	¢/kWh	7.445	7.324
Dusk to Dawn Lighting	¢/kWh	2.805	3.352
General Lighting	¢/kWh	7.329	7.306

NOTES:
(1) This informational sheet is supplemental to Sheet No. 21 in Rate BES - Basic Electric Service (Rate BES) and Sheet No. 319 through Sheet No. 323 in Rider PE - Purchased Electricity (Rider PE).
(2) PECs are designated on retail customer bills as the Electricity Supply Charge pursuant to Rate BES.
(3) PECs include uncollectible factors pursuant to Rate BES and Rider UF - Uncollectible Factors (Rider UF).

BILLING ADJUSTMENTS

The following charges are applied to the Monthly Rate of each rate schedule as indicated and are calculated in accordance with the formula specified by the Florida Public Service Commission.

RATE SCHEDULE	FUEL ¢/kWh	FUEL ¢/kWh	FUEL ¢/kWh	CONSERVATION ¢/kWh	CONSERVATION $/kW	CAPACITY ¢/kWh	CAPACITY $/kW	ENVIRON-MENTAL ¢/kWh
	Levelized	On-Peak	Off-Peak					
RS-1, 1st 1,000 kWh	3.857			0.188		0. 621		0.179
RS-1, all addn kWH	4.857			0.188		0. 621		0.179
RST-1		4.674	3.958	0.188		0. 621		0.179
GS-1, WIES-1	4.181			0.186		0. 612		0.177
GST-1		4.674	3.958	0.186		0. 612		0.177
GSD-1	4.181				0.62		1.93	0.157
GSD-1 w/SDTR (June-Sept)		4.764	3.996		0.62		1.93	0.157
GSD-1 w/SDTR (Jan-May & Oct-Dec)	4.181				0.62		1.93	0.157
GSDT-1, HLFT-1		4.674	3.958		0.62		1.93	0.157
GSDT-1 w/SDTR (June-Sept)		4.764	3.996		0.62		1.93	0.157
GSDT-1 w/SDTR (Jan-May & Oct-Dec)		4.674	3.958		0.62		1.93	0.157
GSLD-1, CS-1	4.177				0.75		2.31	0.153
GSLD-1 w/SDTR (June-Sept)		4.760	3.993		0.75		2.31	0.153
GSLD-1 w/SDTR (Jan-May & Oct-Dec)	4.177				0.75		2.31	0.153
GSLDT-1, CST-1, HLFT-2		4.670	3.954		0.75		2.31	0.153
GSLDT-1 w/SDTR (June-Sept)		4.760	3.993		0.75		2.31	0.153
GSLDT-1 w/SDTR (Jan-May & Oct-Dec)		4.670	3.954		0.75		2.31	0.153
GSLD-2, CS-2	4.146				0.75		2.21	0.140
GSLD-2 w/SDTR (June-Sept)		4.733	3.970		0.75		2.21	0.140
GSLD-2 w/SDTR (Jan-May & Oct-Dec)	4.146				0.75		2.21	0.140
GSLDT-2, CST-2, HLFT-3		4.641	3.929		0.75		2.21	0.140
GSLDT-2 w/SDTR (June-Sept)		4.733	3.970		0.75		2.21	0.140
GSLDT-2 w/SDTR (Jan-May & Oct-Dec)		4.641	3.929		0.75		2.21	0.140

NOTE: The Billing Adjustments for additional Rate Schedules are found on Sheet No. 8.030.1

(Continued on Sheet No. 8.030.1)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: April 2, 2010

ELECTRIC

General Service Demand Electric Rate Schedule GSD

MONTHLY RATE:

Customer Charge: $15.00

Generation Demand Charge:

Summer: All Kw of billing demand per month @ $9.03

or

Winter: All Kw of billing demand per month @ $4.50

Plus

Energy Charge:

All kWh per month @.01882

Plus

Purchase Power Adjustment: All kWh per month @.03445

Summer periods are June, July, August and September. For all other months the winter rate shall apply.

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 32

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 32 Sheet 1

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed December 21, 1998

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 6 Sheets

06-KCPE-828-RTS
Approved
Kansas Corporation Commission
December 4, 2006
/S/ Susan K. Duffy

MEDIUM GENERAL SERVICE
Schedule MGS

AVAILABILITY:

For electric service through one meter to a customer using electric service for purposes other than those included in the availability provisions of the Residential Service Rate Schedule. At the Company's discretion, service may be provided through more than one meter where it is economical for the Company to do so.

For electric service through a separately metered circuit for water heating connected prior to March 1, 1999.

For secondary electric service through a separately metered circuit for electric space heating purposes. Electric space heating equipment may be supplemented by or used as a supplement to wood burning fireplaces, wood burning stoves, active or passive solar heating, and in conjunction with fossil fuels where the combination of energy sources results in a net economic benefit to the customer. Electric space heating equipment shall be permanently installed, thermostatically controlled, and of a size and design approved by the Company. In addition to the electric space heating equipment, only permanently installed all electric equipment, used to cool or air condition the same space which is electrically heated, may be connected to the separately metered circuit.

Standby, breakdown, or supplementary service will not be supplied under this schedule unless the customer first enters into a special contract which includes technical and safety requirements. These requirements, and the associated interconnection costs, shall be reasonable and assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics. Seasonal service will not be supplied under this schedule. Temporary service supplied under this schedule will be connected and disconnected in accordance with the General Rules and Regulations.

APPLICABILITY:

Applicable to multiple-occupancy buildings when the tenants or occupants of the building are furnished with electric service on a rent inclusion basis and the customer qualifies under Sections 9.03 – 9.08 of Company's General Rules and Regulations pertaining to Metering.

This rate also will be applied to the combined use of a customer at the premises where two or more classes of service (such as one-phase and three-phase services) to the customer at such premises are measured by separate meters, but only in the case of customers connected prior to August 25, 1976. Monthly Maximum Demand will be computed as the sum of the individual meters' monthly maximum 30-minute interval demand. Customers with more than one class of service connected on or after August 25, 1976 will be billed separately for each class of service.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof, except in the case of temporary service.

Issued: December 8, 2006 (Month Day Year)	FILED
Effective: January 1, 2007 (Month Day Year)	THE STATE CORPORATION COMMISSION OF KANSAS
By: Chris B. Giles, Vice-President (Title)	By: (Secretary)

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 32

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 32 Sheet 2

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed November 20, 2007

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 2 of 6 Sheets

MEDIUM GENERAL SERVICE
Schedule MGS **(Continued)**

RATE FOR SERVICE AT SECONDARY VOLTAGE:

A. CUSTOMER CHARGE:

(i) Customer pays the following charge per month: $40.71

(ii) plus, additional meter charge for customers with separately metered space heat: $1.88

B. FACILITIES CHARGE:

Per kW of Facilities Demand per month $2.405

C. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$3.365	$1.704

D. ENERGY CHARGE:

kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.07631 per kWh	$0.06833 per kWh
Next 180 Hours Use per month	$0.04783 per kWh	$0.03835 per kWh
Over 360 Hours Use per month	$0.04840 per kWh	$0.03228 per kWh

E. SEPARATELY METERED SPACE HEAT:

When the customer has separately metered electric space heating equipment of a size and design approved by the Company, the kWh used for electric space heating shall be billed as follows:

(i) Applicable during the Winter Season:.
$0.03046 per kWh per month.

(ii) Applicable during the Summer Season:
The demand established and energy used by equipment connected to the space heating circuit will be added to the demands and energy measured for billing under the rates above and for the determination of the Minimum Monthly Bill.

09-KCPE-246-RTS
Approved
Kansas Corporation Commission
July 24, 2009
/S/ Susan K. Duffy

SAC

Issued: July 28, 2009 (Month Day Year)	FILED
Effective: August 1, 2009 (Month Day Year)	THE STATE CORPORATION COMMISSION OF KANSAS
By: Curtis D. Blanc, Sr. Director (Title)	By ____ Secretary

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 32

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 32 Sheet 3

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed November 20, 2007

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 3 of 6 Sheets

MEDIUM GENERAL SERVICE
Schedule MGS **(Continued)**

RATE FOR SERVICE AT PRIMARY VOLTAGE:

A. CUSTOMER CHARGE:

Customer pays the following charge per month: $40.71

B. FACILITIES CHARGE:

Per kW of Facilities Demand per month $2.030

C. D EMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$3.288	$1.666

D. ENERGY CHARGE:

kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.07437 per kWh	$0.06672 per kWh
Next 180 Hours Use per month	$0.04634 per kWh	$0.03744 per kWh
Over 360 Hours Use per month	$0.04428 per kWh	$0.02943 per kWh

09-KCPE-246-RTS
Approved
Kansas Corporation Commission
July 24, 2009
/S/ Susan K. Duffy

SAC

Issued: July 28, 2009 (Month Day Year)	FILED
Effective: August 1, 2009 (Month Day Year)	THE STATE CORPORATION COMMISSION OF KANSAS
By: Curtis D. Blanc Sr. Director (Title)	By: (Secretary)

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 32

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 32 Sheet 4

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed November 20, 2007

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 4 of 6 Sheets

MEDIUM GENERAL SERVICE
Schedule MGS **(Continued)**

REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.557 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

ENERGY COST ADJUSTMENT:

Energy Cost Adjustment, Schedule ECA, shall be applicable to all customer billings under this schedule.

CUSTOMER DEFINITIONS:

Secondary Voltage Customer - Receives service on the low side of the line transformer.

Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

Water Heating Customer - Customer connected prior to March 1, 1999, that receives service through a separately metered circuit as the sole means of water heating with an electric water heater of a size and design approved by the Company.

09-KCPE-246-RTS
Approved
Kansas Corporation Commission
July 24, 2009
/S/ Susan K. Duffy

SAC

Issued: July 28, 2009 (Month Day Year)	FILED
Effective: August 1, 2009 (Month Day Year)	THE STATE CORPORATION COMMISSION OF KANSAS
By: Curtis D. Blanc, Sr. Director (Title)	By: (Secretary)

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 32

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 32 Sheet 5

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed December 21, 1998

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 5 of 6 Sheets

MEDIUM GENERAL SERVICE
Schedule MGS **(Continued)**

DETERMINATION OF DEMANDS:

Demand will be determined by demand instruments or, at the Company's option, by demand tests.

MINIMUM DEMAND:

25 kW for service at Secondary Voltage.
26 kW for service at Primary Voltage.

MONTHLY MAXIMUM DEMAND:

The Monthly Maximum Demand is defined as the sum of:

a. The highest demand indicated in any 30-minute interval during the month on all non-space heat and non-water heat meters.

b. Plus, the highest demand indicated in any 30-minute interval during the month on the space heat meter, if applicable.

c. Plus, the highest demand indicated in any 30-minute interval during the month on the water heat meter, if applicable.

FACILITIES DEMAND:

Facilities Demand shall be equal to the higher of: (a) the highest Monthly Maximum Demand occurring in the last twelve (12) months including the current month or (b) the Minimum Demand.

06-KCPE-828-RTS
Approved
Kansas Corporation Commission
December 4, 2006
/S/ Susan K. Duffy

Issued:	December 8, 2006 (Month Day Year)	FILED
Effective:	January 1, 2007 (Month Day Year)	THE STATE CORPORATION COMMISSION OF KANSAS
By:	Chris B. Giles, Vice-President (Title)	By: (Secretary)

MEDIUM GENERAL SERVICE
Schedule MGS **(Continued)**

DETERMINATION OF DEMANDS (Continued):

BILLING DEMAND:

Billing Demand shall be equal to the higher of: (a) the Monthly Maximum Demand in the current month or (b) the Minimum Demand.

DETERMINATION OF HOURS USE:

Total Hours Use in the Summer Season shall be determined by dividing the total monthly kWh on all meters by the Monthly Maximum Demand in the current month. Total Hours Use in the Winter Season shall be determined by dividing the total monthly kWh on all meters (excluding separately metered space heat kWh) by the Monthly Maximum Demand (excluding separately metered space heat kW) in the current month. The kWh associated with a given number of Hours Use is computed by multiplying the Monthly Maximum Demand (excluding separately metered space heat kW in the Winter Season) by that number of Hours Use.

METERING AT DIFFERENT VOLTAGES:

The Company may, at its option, install metering equipment on the secondary side of a Primary Voltage Customer's transformer. In that event, the customer's metered demand and energy shall be increased either by the installation of compensation metering equipment, or by 2.34% if metering equipment is not compensated.

The Company may also, at its option, install metering equipment on the primary side of the transformer for a Secondary Voltage Customer. In this case, the customer's metered demand and energy shall be decreased by 2.29%, or alternatively, compensation metering may be installed.

TAX ADJUSTMENT:

Tax Adjustment Schedule TA shall be applicable to all customer billings under this schedule.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

06-KCPE-828-RTS
Approved
Kansas Corporation Commission
December 4, 2006
/S/ Susan K. Duffy

Issued: December 8, 2006 (Month Day Year)	FILED
Effective: January 1, 2007 (Month Day Year)	THE STATE CORPORATION COMMISSION OF KANSAS
By: Chris B. Giles, Vice-President (Title)	By: (Secretary)

STATEMENT OF RATES

EFFECTIVE RATES APPLICABLE TO NEVADA POWER COMPANY ELECTRIC SCHEDULES

Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	TRED	REPR	UEC	DEAA	Total Rate	
LGS-1 - Large General Service - 1								
Basic Service Charge, per meter per month							$14.90	
Consumption Charge per kWh								
All Usage	$0.01922	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.07591	(R)
Demand Charge, All kW per kW							$3.92	
Facilities Charge, All kW per kW							$3.90	
OLGS-1-TOU – Optional Large General Service – 1 - Time-of-Use								
Basic Service Charge, per meter per month							$17.10	
Consumption Charge per kWh								
Summer On-Peak	$0.14680	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.20349	(R)
Summer Off-Peak	$0.01189	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06858	(R)
Summer GSHEVRR (General Service Hybric Electric Vehicle Recharge Rider)	$0.00506	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06175	(R)
Winter All other	$0.00376	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06045	(R)
Winter GSHEVRR (General Service Hybrid Electric Vehicle Recharge Rider)	($0.00226)	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05443	(R)
Demand Charge per kW								
Summer On-Peak Period							$7.50	
Winter Period							$0.16	
Facilities Charge, All kW per kW							$3.90	
LGS-2 – Large General Service - 2								
Secondary Distribution Voltage								
Basic Service Charge, per meter per month							$210.70	
Consumption Charge per kWh								
Summer On-Peak Period	$0.04812	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.10481	(R)
Summer Mid-Peak Period	$0.02160	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.07829	(R)
Summer Off-Peak Period	$0.00064	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05733	(R)
All other Periods	$0.00716	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06385	(R)
Demand Charge per kW								
Summer On-Peak Period							$13.79	
Summer Mid-Peak Period							$1.90	
Summer Off-Peak Period							$0.00	
All other Periods							$0.35	
Facilities Charge all kW per kW							$3.10	

(Continued)

STATEMENT OF RATES

EFFECTIVE RATES APPLICABLE TO NEVADA POWER COMPANY ELECTRIC SCHEDULES

Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	TRED	REPR	UEC	DEAA	Total Rate	
LGS-2– Large General Service – 1 (Continued)								
Primary Distribution Voltage								
Basic Service Charge, per meter per month							$291.90	
Consumption Charge per kWh								
Summer On-Peak Period	$0.03832	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.09501	(R)
Summer Mid-Peak Period	$0.01437	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.07106	(R)
Summer Off-Peak Period	$0.00064	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05733	(R)
All other Periods	$0.00065	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05734	(R)
Demand Charge per kW								
Summer On-Peak Period							$14.34	
Summer Mid-Peak Period							$2.02	
Summer Off-Peak Period							$0.00	
All other Periods							$0.34	
Facilities Charge all kW per kW							$2.60	
Transmission Voltage								
Basic Service Charge, per meter per month							$302.30	
Consumption Charge per kWh								
Summer On-Peak Period	$0.03435	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.09104	(R)
Summer Mid-Peak Period	$0.01162	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06831	(R)
Summer Off-Peak Period	$0.00064	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05733	(R)
All other Periods	$0.00064	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05733	(R)
Demand Charge per kW								
Summer On-Peak Period							$14.34	
Summer Mid-Peak Period							$2.02	
Summer Off-Peak Period							$0.00	
All other Periods							$0.34	
Facilities Charge per dollar of Utility Investment (See note 8)							$0.00618	
Facilities Charge per dollar of Contributed Investment (See note 8)							$0.00125	
Facilities Charge, all kW per kW							$0.60	
LGS-3 – Large General Service - 3								
Secondary Distribution Voltage								
Basic Service Charge, per meter per month							$215.30	
Consumption Charge per kWh								
Summer On-Peak Period	$0.04192	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.09861	(R)
Summer Mid-Peak Period	$0.01757	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.07426	(R)
Summer Off-Peak Period	$0.00071	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05740	(R)
All other Periods	$0.00359	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06028	(R)

(Continued)

STATEMENT OF RATES

EFFECTIVE RATES APPLICABLE TO NEVADA POWER COMPANY ELECTRIC SCHEDULES

Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	TRED	REPR	UEC	DEAA	Total Rate	
LGS-3 – Large General Service – 3 (Continued)								
Secondary Distribution Voltage (Continued)								
Demand Charge per kW								
Summer On-Peak Period							$16.83	
Summer Mid-Peak Period							$2.40	
Summer Off-Peak Period							$0.00	
All other Periods							$0.50	
Facilities Charge all kW per kW							$3.36	
Primary Distribution Voltage								
Basic Service Charge, per meter per month							$291.10	
Consumption Charge per kWh								
Summer On-Peak Period	$0.03746	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.09415	(R)
Summer Mid-Peak Period	$0.01433	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.07102	(R)
Summer Off-Peak Period	$0.00071	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05740	(R)
All other Periods	$0.00081	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05750	(R)
Demand Charge per kW								
Summer On-Peak Period							$18.37	
Summer Mid-Peak Period							$2.69	
Summer Off-Peak Period							$0.00	
All other Periods							$0.50	
Facilities Charge all kW per kW							$3.29	
Transmission Voltage								
Basic Service Charge, per meter per month							$279.20	
Consumption Charge per kWh								
Summer On-Peak Period	$0.02570	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.08239	(R)
Summer Mid-Peak Period	$0.00453	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06122	(R)
Summer Off-Peak Period	$0.00071	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05740	(R)
All other Periods	$0.00071	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05740	(R)
Demand Charge per kW								
Summer On-Peak Period							$15.21	
Summer Mid-Peak Period							$2.15	
Summer Off-Peak Period							$0.00	
All other Periods							$0.40	
Facilities Charge per dollar of Utility investment (See note 8)							$0.00618	
Facilities Charge per dollar of Contributed investment (See note 8)							$0.00125	
Facilities Charge, all kW per Kw							$0.60	

(Continued)

STATEMENT OF RATES

EFFECTIVE RATES APPLICABLE TO NEVADA POWER COMPANY ELECTRIC SCHEDULES

Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	TRED	REPR	UEC	DEAA	Total Rate	
LGS-X – Large General Service - Extra Large (See Note 10, 11 and 12)								
Secondary Distribution Voltage								
Basic Service Charge, per meter per month							$7000.00	
Consumption Charge per kWh								
Summer On-Peak Period	$0.02948	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.08617	(R)
Summer Mid-Peak Period	$0.00743	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06412	(R)
Summer Off-Peak Period	$0.00071	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05740	(R)
All other Periods	$0.00548	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06217	(R)
Demand Charge per kW								
Summer On-Peak Period							$11.22	
Summer Mid-Peak Period							$1.65	
Summer Off-Peak Period							$0.00	
All other Periods							$0.50	
Facilities Charge all kW per kW							$0.66	
Meter Charge per additional meter per month							$112.60	
Primary Distribution Voltage								
Basic Service Charge, per meter per month							$7000.00	
Consumption Charge per kWh								
Summer On-Peak Period	$0.03819	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.09488	(R)
Summer Mid-Peak Period	$0.01501	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.07170	(R)
Summer Off-Peak Period	$0.00071	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05740	(R)
All other Periods	$0.00163	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05832	(R)
Demand Charge per kW								
Summer On-Peak Period							$19.75	
Summer Mid-Peak Period							$2.97	
Summer Off-Peak Period							$0.00	
All other Periods							$0.50	
Facilities Charge all kW per kW							$1.67	
Meter Charge per additional meter per month							$167.00	

(Continued)

STATEMENT OF RATES

EFFECTIVE RATES APPLICABLE TO NEVADA POWER COMPANY ELECTRIC SCHEDULES

Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	TRED	REPR	UEC	DEAA	Total Rate	
LGS-X – Large General Service - Extra Large (Continued)								
Transmission Voltage								
Basic Service Charge, per meter per month							$7000.00	
Consumption Charge per kWh								
Summer On-Peak Period	$0.03123	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.08792	(R)
Summer Mid-Peak Period	$0.00912	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06581	(R)
Summer Off-Peak Period	$0.00071	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05740	(R)
All other Periods	$0.00072	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05741	(R)
Demand Charge per kW								
Summer On-Peak Period							$18.25	
Summer Mid-Peak Period							$2.74	
Summer Off-Peak Period							$0.00	
All other Periods							$0.50	
Facilities Charge all kW per kW							$0.00	
Meter Charge per additional meter per month							$177.40	
LGS-WP-2 – Large General Service - Water Pumping - 2								
Secondary Distribution Voltage								
Basic Service Charge, per meter per month							$210.70	
Consumption Charge per kWh								
Summer On-Peak Period	$0.06170	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.11839	(R)
Summer Mid-Peak Period	$0.04355	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.10024	(R)
Summer Off-Peak Period	$0.00183	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.05852	(R)
All other Periods	$0.00584	$0.05524	$0.00078	$0.00028	$0.00039	$0.00000	$0.06253	(R)
Demand Charge per kW (During hours of curtailment)								
Summer On and Mid-Peak Period							$15.69	
Summer Off-Peak Period							$0.00	
All other Periods							$0.35	
Facilities Charge all kW per kW							$1.43	

(Continued)

PECO Energy Company

RATE-HT-SP HIGH-TENSION POWER SUPER PEAK TIME OF USE (C)

AVAILABILITY.

To customers with service on or after January 1, 2011 with peak measured demands of less than or equal to 500 kW who have untransformed service from the Company's standard high-tension lines, where the customer installs, owns, and maintains, any transforming, switching and other receiving equipment required service hereunder is restricted to customers that obtain full requirements electric supply from the Company under Default Service.

Customers may not receive supply from an alternative electric generation supplier for one year from the effective date of receiving service under this rate.

CURRENT CHARACTERISTICS.

Standard high-tension service.

DEFINITION OF PEAK-HOURS. On-Peak Hours are defined as the hours between x:xx am and x:xx pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays during the summer period (June through September). Off-Peak Hours are defined as the hours other than those specified as on-peak hours. The Company will establish the On-Peak Hours in conjunction with the calculation of the energy supply charge as described below.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $291.52

VARIABLE DISTRIBUTION SERVICE CHARGE:

$2.57 per kW of billing demand
0.90¢ per kWh of the first 150 hours' use of billing demand
0.53¢ per kWh of the next 150 hours' use of billing demand, but not more than 7,500,000 kWh
0.17¢ per kWh for additional use.

ENERGY SUPPLY CHARGE: The Company will calculate the energy supply charge following the release of its 2011 default service procurement results.

SUMMER MONTHS (June through September)
xx.xx¢ per off-peak kWh
y.yy¢ per on-peak kWh
WINTER MONTHS (October through May)
z.zz¢ per off-peak kWh

ENERGY EFFICIENCY CHARGE: $0.91¢ per kW of Peak Load Contribution

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For customers supplied at 33,000 volts: 7¢ per kW of measured demand.
For customers supplied at 69,000 volts: 28¢ per kW for first 10,000 kW of measured demand.
For customers supplied over 69,000 volts: 28¢ per kW for first 100,000 kW of measured demand.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT, PROVISION FOR RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS and PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE. (C)

(C) Indicates Change

Pacific Gas and Electric Company
Bundled Commercial/General Service Electric Rates at a Glance

Rates Effective:
June 1, 2010, to Present

Rate Schedule	Customer Charge	Season	Time-of-Use Period	Demand Charge (per kW)			Time-of-Use Period	Total Energy Charge (per kWh)			PDP[1] Charges	PDP[2] Credits DEMAND (per kW)			PDP[2] Credits ENERGY (per kWh)			"Average" Total Rate[3] (per kWh)
A-1	Single Phase Service per meter/day =$0.29569 Polyphase Service per meter/day =$0.44353	Summer		-				$0.19937			-	-			-			
		Winter		-				$0.14373			-	-			-			
A-1 TOU	Single Phase Service per meter/day =$0.29569 Polyphase Service per meter/day =$0.44353	Summer		-			On peak	$0.22456			$0.60	-			($0.01096)			$0.18075
							Part Peak	$0.19869							($0.01096)			
							Off Peak	$0.18326							($0.01096)			
		Winter		-			Part Peak	$0.14910				-			-			
							Off Peak	$0.13805										
A-6 TOU	Single phase service per meter/day =$0.29569; Polyphase service per meter/day =$0.44353. Plus Meter charge =$0.20107per day for A6 or A6X; =$0.05914 per day for A6W[5]	Summer		-			On peak	$0.45331			$1.20	-			($0.08786)			$0.17419
							Part Peak	$0.20061							($0.01757)			
							Off Peak	$0.11691							-			
		Winter		-			Part Peak	$0.16567				-			-			
							Off Peak	$0.12084										
				Secondary	Primary	Transmission		Secondary	Primary	Transmission		Secondary	Primary	Transmission	Secondary	Primary	Transmission	
A-10 (Table A)	$3.94251 per meter per day	Summer		$10.88	$10.27	$7.89		$0.14001	$0.13325	$0.11682	-	-	-	-	-	-	-	$0.16041
		Winter		$6.52	$6.01	$4.15		$0.10652	$0.10132	$0.09017								
A-10 TOU (Table B)	$3.94251 per meter per day	Summer		$10.88	$10.27	$7.89	Peak	$0.16289	$0.15391	$0.13655	$0.90	($1.54)	($1.60)	($1.79)	($0.01055)	($0.01103)	($0.00915)	Secondary $0.16049 Primary $0.14923 Transmission $0.12343
							Part-Peak	$0.14031	$0.13380	$0.11714					($0.01055)	($0.01103)	($0.00915)	
							Off-Peak	$0.12687	$0.12133	$0.10557					($0.01055)	($0.01103)	($0.00915)	
		Winter		$6.52	$6.01	$4.15	Part-Peak	$0.11195	$0.10563	$0.09424		-	-	-	-	-	-	
							Off-Peak	$0.10116	$0.09716	$0.08625								
E-19 TOU	Meter charge: =$4.11992/day for E19 V or X; =$3.97799/day for E19W[4]; =$13.55236/day for E19S mandatory; =$19.71253/day for E19P mandatory; =$39.42505/day for E19T mandatory	Summer	Max. Peak	$13.05	$11.80	$9.16	Peak	$0.15257	$0.15217	$0.11306	$1.20	($6.10)	($5.87)	($5.67)	($0.00355)	($0.00179)	($0.00000)	Secondary $0.13967 Primary $0.13301 Transmission $0.11832
			Part Peak	$2.99	$2.70	$2.07	Part Peak	$0.10525	$0.10319	$0.09101		($1.30)	($1.26)	($1.28)	($0.00071)	($0.00036)	($0.00000)	
			Maximum	$8.58	$7.47	$5.42	Off Peak	$0.08591	$0.08205	$0.07783		-	-	-	-	-	-	
		Winter	Part Peak	$1.12	$0.84	$0.00	Part Peak	$0.09397	$0.08898	$0.08301		-	-	-	-	-	-	
			Maximum	$8.58	$7.47	$5.42	Off Peak	$0.08304	$0.07823	$0.07391								

[1] Peak Day Pricing (PDP) (Consecutive Day and Four-Hour Event Option). All Usage During PDP Event. See specific tariff for further details.
[2] Peak Day Pricing (PDP) (Consecutive Day and Four-Hour Event Option). See specific tariff for further details.
[3] Average rates based on estimated forecast. Average rates provided only for general reference, and individual customer's average rate will depend on its applicable kW, kWh, and TOU data.
[4] Effective May 1, 2006, the voluntary TOU one time reprogramming charge of $87 if there is a TOU meter already present, and one time $443 meter installation charge if there is no TOU meter, were eliminated.
[5] The lower daily TOU meter charge continues to apply to customers who were on Rate W as of May 1, 2006. Rate X applies to all other customers.

This table provided for comparative purposes only. See current tariffs for full information regarding rates, application, eligibility, average rate limiter and additional options.

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

2nd Sub. Forty-sixth Revised Sheet No. 20

Forty-fifth Revised Cancels Sheet No. 20

ELECTRIC RATES

RATE SCHEDULE SUMMATION SHEET**

Total Effective Monthly Rate*

Rate Schedule	Sheet No.	Service & Facility Charge	Energy Charge per kWh		Demand Charge per kW		
R	30	6.85	***Winter	0.09282		--	R
			***Summer T-1	0.09282		--	R
			***Summer T-2	0.13741			R
RD	33	12.43	Both	0.05068	Winter	10.08	RR
			Seasons		Summer	12.09	R
C	40	10.91	Winter	0.08644		--	R
			Summer	0.11211		--	R
SGL	43	40.58	Winter	0.19194	Both	4.91	R
			Summer	0.22948	Seasons		R
SG	44	40.58		0.03781	Winter	12.33	RR
			On-Peak	0.04617	Summer	15.33	RR
			Off-Peak	0.03149	Both	4.91	R
PG	52	309.42	On-Peak	0.04583	Winter	11.41	RR
			Off-Peak	0.03123	Summer	14.46	RR
					Both	4.04	
TG	62	Varies	On-Peak	0.04550	Winter	10.95	RR
			Off-Peak	0.03098	Summer	13.99	RR

*The total effective monthly rates are the cumulative total of the applicable base rates and the applicable Electric Rate Adjustments. The Service and Facility Charge for all rate schedules is calculated by adding the applicable Service and Facility Charge plus the Base Rate Adjustments, plus the Total Rate Adjustments. The Energy Charges for Schedules R, RD, C, SGL, SG, are calculated by adding the applicable Energy Charge, plus the Base Rate Adjustments, plus the applicable Non-Base Rate Adjustments, plus the Total Rate Adjustments.

**The rates and charges included in the Rate Schedule Summation Sheets are for informational and billing estimation purposes only.

*** The kilowatt-hours in the Winter Season will not be billed on a tiered rate. In the Summer Season, the first 500 kilowatt-hours will be billed at Tier 1 (T-1) and any usage over 500 kilowatt-hours will be billed at Tier 2 (T-2).

(Continued on Sheet No. 21)

ADVICE LETTER NUMBER 1561 Second Amended

ISSUE DATE June 29, 2010

DECISION NUMBER R08-1243

VICE PRESIDENT, Rates & Regulatory Affairs

EFFECTIVE DATE July 1, 2010

ELECTRIC RATES	RATE	
SECONDARY GENERAL SERVICE		
SCHEDULE SG		

APPLICABILITY

Applicable to electric power service supplied at secondary voltage. Not applicable to standby or resale service.

MONTHLY RATE

Service and Facility Charge:	$40.00	I
Demand Charge:		
All kilowatts of billing demand, per kW		
Distribution Demand..................................	4.84	C
Generation and Transmission Demand - Summer Season...	10.96	CI
Generation and Transmission Demand - Winter Season...	8.00	CR
Energy Charge:		
All kilowatt hours used, per kWh....................	$ 0.00473	I

The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.

MONTHLY MINIMUM

The Service and Facility Charge plus the Demand Charge.

OPTIONAL SERVICE

Customers receiving service under this rate may elect to receive interruptible service under the Interruptible Service Option Credit.

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month.

DETERMINATION OF BILLING DEMAND

Billing demand, determined by meter measurement, shall be the maximum fifteen (15) minute integrated kilowatt demand used during the month, except as set forth in the Commercial and Industrial Rules and Regulations.

(Continued on Sheet No. 44A)

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$3.96 in each month [$4.24 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.8307	$ 4.0988	per kilowatt of Monthly Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 7.1094	$ 7.6071	per kilowatt of Monthly Peak Demand

Distribution Kilowatthour Charges:

In each of the months of October through May		In each of the Months of June through September		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$ 0.005883	$ 0.006295	$ 0.011717	$ 0.012537	per kilowatthour

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Securitization Transition Charges:

These charges include the Transition Bond Charge and the MTC-Tax charge and shall recover costs and associated taxes for transition bonds collected by PSE&G as servicer on behalf of PSE&G Transition Funding LLC. Refer to the Securitization Transition Charges sheet of this Tariff for the current charges.

Date of Issue: June 10, 2010 Effective: June 7, 2010
Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated June 7, 2010
in Docket No. GR09050422

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 8

STATE OF UTAH

Large General Service – 1,000 kW and Over – Distribution Voltage

AVAILABILITY: At any point on the Company's interconnected system where there are facilities of adequate capacity.

APPLICATION: This Schedule is for alternating current, single or three-phase, electric service supplied at Company's available voltage, but less than 46,000 volts through a single point of delivery, for all service required on the Customer's premises. This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in the preceding 18-month period. This Schedule will remain applicable until the Customer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. A Customer who is transferred to this Schedule from a different Schedule for registering 1,000 kW or more at least twice in 18 months and who had never previously been served under this Schedule will, upon request to the Company, be transferred back to Schedule 6 or another appropriate Schedule if the Customer's electric service load has not registered 1,000 kW or more at any time during the subsequent period of at least 18 consecutive months. The Company shall not be responsible for notifying the Customer that said Customer has satisfied the foregoing conditions for transfer to a different Schedule. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. This Schedule is for general nonresidential service, except for multi-unit residential complexes master metered in accordance with the Utah Administrative Code, Section R746-210. Service under this Schedule is also available to common areas associated with residential complexes.

MONTHLY BILL:

Customer Service Charge:
$55.00 per Customer

Facilities Charge:
$3.77 per kW

(continued)

ELECTRIC SERVICE SCHEDULE NO. 8 - Continued

MONTHLY BILL: (continued)

Power Charge:

Billing Months - May through September inclusive
On-Peak: $12.33 per kW
Off-Peak: None

Billing Months - October through April inclusive
On-Peak: $8.88 per kW
Off-Peak: None

Energy Charge:

Billing Months - May through September inclusive
4.0021 ¢ per kWh for all On-Peak kWh
2.6987¢ per kWh for all Off-Peak kWh

Billing Months - October through April inclusive
3.1328¢ per kWh for all On-Peak kWh
2.6987¢ per kWh for all Off-Peak kWh

Voltage Discount: Where Customer takes service from Company's available lines of 2,300 volts or higher and provides and maintains all transformers and other necessary equipment, the Voltage Discount based on measured On-Peak Power will be:

$0.90 per kW

SURCHARGE ADJUSTMENT: All monthly bills shall be adjusted in accordance with Schedule 193.

FACILITIES KW: All kW as shown by or computed from the reading of Company's Power meter for the 15-minute period of Customer's greatest use at any time during the month, adjusted for Power Factor to the nearest kW.

POWER: The kW as shown by or computed from the readings of Company's Power meter for the 15-minute On-Peak period of Customer's greatest use during the month, adjusted for Power Factor to the nearest kW.

POWER FACTOR: The On-Peak Power Charge is based on the Customer maintaining at all times a Power Factor of 90% lagging, or higher, as determined by measurement. If the average Power Factor is found to be less than 90% lagging, the On-Peak Power, as recorded by the Company's meter, will be increased by 3/4 of 1% for every 1% that the Power Factor is less than 90%.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 8 - Continued

TIME PERIODS:

On-Peak:	October through April inclusive 7:00 a.m. to 11:00 p.m., Monday thru Friday, except holidays. May through September inclusive 1:00 p.m. to 9:00 p.m., Monday thru Friday, except holidays.
Off-Peak:	All other times.

Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day, and Christmas Day. When a holiday falls on a Saturday or Sunday, the Friday before the holiday (if the holiday falls on a Saturday) or the Monday following the holiday (if the holiday falls on a Sunday) will be considered a holiday and consequently Off-Peak.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005 the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

FORCE MAJEURE: Neither Company nor Customer shall be subject to any liability or damages for inability to provide or receive service to the extent that such failure shall be due to causes beyond the control of either Company or Customer, including but not limited to the following: (a) operation and effect of any rules, regulations and orders promulgated by any Commission, municipality, or governmental agency of the United States, or subdivision thereof; (b) restraining order, injunction, or similar decree of any court; (c) war; (d) flood; (e) earthquake; (f) act of God; (g) sabotage; or (h) strikes or boycotts. Should any of the foregoing occur, the minimum Billing Demand that would otherwise be applicable under this Schedule shall be waived and the Customer will have no liability for service until such time as the Customer is able to resume service, except for any term minimum guarantees designed to cover special facilities extension costs. The party claiming Force Majeure under this provision shall make every reasonable attempt to remedy the cause thereof as diligently and expeditiously as possible.

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

I. Applicability

Applicable to single or three phase service, delivered at such nominal voltage as the customer selects from among those which the District designates are available at the customer's premises. This schedule is mandatory for all commercial and industrial (C&I) customers whose monthly demand is 1,000 kW or over for three consecutive months during the preceding 12 months. Customers will remain on this rate schedule until their demand falls below 1000 kW for 12 consecutive months. Service under this schedule is subject to meter availability. The demand for any month will be the maximum 15-minute kW delivery during the month.

II. Firm Service Rate

	Large C&I	Large C&I	Large C&I
Rate Category	GUS_L	GUP_L	GUT_L
Voltage Level	**Secondary**	**Primary**	**69KV**
Winter Season - October 1 through May 31			
Service Charge - per month per meter	$94.60	$94.60	$250.45
Facilities Charge *(per 12 months max kW or installed capacity)*	$3.50	$3.35	$2.70
Energy Charge			
On-Peak ¢/kWh	9.43¢	8.97¢	8.64¢
Off-Peak ¢/kWh	7.47¢	6.99¢	6.84¢
Summer Season - June 1 through September 30			
Service Charge - per month per meter	$94.60	$94.60	$250.45
Facilities Charge *(per 12 months max kW or installed capacity)*	$3.50	$3.35	$2.70
Energy Charge			
Super-Peak ¢/kWh	14.70¢	12.12¢	11.77¢
On-Peak ¢/kWh	11.75¢	11.04¢	10.34¢
Off-Peak ¢/kWh	9.39¢	8.57¢	8.44¢

Solar Surcharge is applied to all kWh regardless of season as outlined in Sheet No. 1-SB-1

III. Rate Option Menu

(A) Energy Assistance Program for Non-Profit Agencies

Please see Sheet No. 1-EAPR-1 for details on the Energy Assistance Program.

(B) Campus Rates

Campus billing is a condition whereby the customer is served from a common address or industrial campus and has several accounts or services entrances on the same contiguous campus. Campus billing provides for either hardwire or post metering combination of these accounts to a single load shape for billing purposes. This option would have the characteristics of avoiding multiple service charges. The following criteria define the conditions under which campus rates would be granted:

1. Contiguous site.
2. Same legal entity buying and consuming the power at the site.
3. No sub-metering on campus to third parties.
4. Special facilities charges applied to recover additional meter/metering expense.
5. Single point of contact at the place of business both for billing and service questions.
6. All accounts served from a common rate and service voltage.
7. Use of parallel systems for shifting load between different rate offerings will be considered a violation of terms of this agreement. The District shall have the right to corrective billing on a single rate and full reimbursement of waived service charges.
8. This type of service requires interval metering on each service entrance. Customers at the secondary service level will be required to pay the service charge associated with primary service to account for additional costs to the District. A monthly service fee will be charged for the additional costs of multiple site metering.

(C) Standby Service Option

This option is for general service customers who operate, in whole or in part, customer-owned generator(s) on their premises and where 1) the output connects to the District's electrical system, and 2) the District must stand ready to provide backup or maintenance service to replace the generator(s).

Standby Service Charge ($/kW of Contract Capacity per month)

Secondary Distribution Voltage $6.10
Primary Distribution Voltage $4.85
69 kV Voltage $2.45

"Contract Capacity" is a fixed kilowatt value determined by the rating of the generator unit. In addition to the standby service charge, the District will continue to bill for all applicable charges under this rate schedule. These charges include customer and facility charges, as well as demand and energy charges for District-provided power.

Optional Metered Standby Service Charge
The customer may elect to base the standby charge on actual metered generator output in relation to total site load, which may result in a different standby billing than one based on contract capacity. This option requires the customer to pay for the installation and monthly maintenance of special metering equipment at both the generator and the customer's SMUD meter.

This option uses a metered standby kW instead of contract capacity kW to determine the standby service charge. The formula is as follows:

metered standby kW = (maximum site kW) - (SMUD billing kW)

where:

"maximum site kW" is the highest coincident sum of the hourly generator output, if any, and the SMUD metered load for the billing period, and

"SMUD billing kW" is the maximum hourly load recorded at the customer meter during the previous 12 months.

(D) Economic Development Rate Option
This option is applicable to full service customers with load in excess of 299 kW who create a minimum of 50 new jobs and add load at a new or expanded site. For existing customers, only the additional load will qualify for the discount. Eligibility for this discount is limited to customers with Standard Industrial Classifications (SIC) 2000-3999 Manufacturing, 4800-4899 Communications, 7300-7499 Business Services and 8700-8799 Professional Services or the equivalent new NAICS codes. Qualified customers must agree to be a full service customer for five years. Qualified customers will receive a reduction of the service, demand, facilities and energy components of their bill, based on the table below.

Economic Development Discount				
Year 1	Year 2	Year 3	Year 4	Year 5
5%	3%	1%	0%	0%

(E) Green Pricing Options
SMUD Community Solar Option
Customers electing this premium service option will receive an additional charge for monthly energy of no less than 1/2¢ and no greater than 2¢ per kWh. Contributions will be held until sufficient funds are available for construction of a solar roof top system.

SMUD Renewable Energy Option
Customers electing this premium power service will receive an additional charge for monthly energy of no less than 1/2¢ and no greater than 2¢ per kWh. SMUD may offer up to three premium rate options representing various blends of renewable resources within the 1/2¢ to 2¢ range. The actual prices will be published each November and will be based on the expected above market cost of renewable resources for the upcoming year. Participation will be limited to the amount of resources that SMUD is able to secure below the 2¢ premium limit.

(F) Implementation of Energy Efficiency Program
Customers who implement a District-sponsored Energy Efficiency program may request a reset of their 12-month historical demand upon completion of the project.

IV. Special Metering Charge
For customers who purchase and install communications hardware and software to transfer energy load data from their meter/recorders to a personal computer, the District will charge a monthly service fee to cover maintenance, software support and the annual licensing fee.

V. Conditions
(A) Type of Electric Service
Firm Service
Standard service where the District provides a continuous and sufficient supply of electricity.

(B) Service Voltage Definition

The following defines the three voltage classes available. The rate shall be determined by the voltage level at which service is taken according to the following:

1. Secondary : This is the voltage class if the definition of "primary" and "69 kV" do not apply to a customer's service.
2. Primary : This is the voltage class if a customer elects to accept service at a voltage level of 12 kV or 21 kV that is available in the area and the District approves such arrangements for a customer whose monthly demand exceeds 300 kW.
3. 69 kV : This is the voltage class if a customer elects to accept service at a voltage level of 69 kV or higher that is available in the area and the District approves such arrangements for a customer whose monthly demand exceeds 500 kW.

(C) Power Factor Adjustment

Accounts with demands of 20 kW or greater may be subject to a power factor adjustment. The District, at its option, may place VAR metering equipment to record reactive power conditions. Effective January 1, 1998, when a customer's monthly power factor falls below 95% leading or lagging, the following billing adjustment will apply:

$$\textit{Energy} \times \$0.0096 \times \left(\frac{95\%}{\textit{Power Factor}} - 1\right)$$

Energy = the total monthly kWh for the account • *Power Factor* = the lesser of the customer's monthly power factor or 95%

Customers that contract with SMUD for power factor corrections will have the power factor adjustment waived for the portion that is covered under the contract.

The fee for correction per KVAR $0.2531

KVAR = maximum 12 month KVAR in excess of 33% of kW.

(D) Time-of-Use Billing Periods

Super-peak hours include the following:

SUMMER SEASON (ONLY) – JUNE 1 through SEPTEMBER 30
Weekdays: Between 2:00 p.m. and 8:00 p.m.

On-peak hours include the following:

WINTER SEASON - OCTOBER 1 through MAY 31
Weekdays: Between 12:00 noon and 10:00 P.M.

SUMMER SEASON - JUNE 1 through SEPTEMBER 30
Weekdays: Between 12:00 noon and 2:00 p.m. and between 8:00 p.m. and 10:00 p.m.

Off-peak hours include the following:

ALL SEASON – JANUARY 1 through DECEMBER 31

All day on Saturdays, Sundays and the following holidays:

Martin Luther King Jr.'s Birthday	3rd Mon. in Jan.
Presidents Day	3rd Mon. in Feb.
Memorial Day	Last Mon. in May
Labor Day	1st Mon. in Sep.
Columbus Day	2nd Mon. in Oct.
Thanksgiving Day	4th Thu. in Nov.
New Year's Day	January 1
Lincoln's Birthday	February 12
Independence Day	July 4
Veterans Day	November 11
Christmas Day	December 25

and all other hours not defined as super-peak or on-peak.

(E) Billing

PRORATION OF CHARGES

BILLING CIRCUMSTANCE	Service Charge	Facilities Charge	BASIS OF PRORATION
Less than 27 days or more than 34 days	Yes	Yes	Relationship between the length of the billing period and 30 days.
Winter/Summer crossover	Yes	Yes	Relationship between the length of the billing period and the number of days winter and summer.

Meter reading for service rendered in accordance with this rate will not be combined for billing purposes unless the convenience of the District is served thereby.

(End)

Tucson Electric Power

A UniSource Energy Company

Pricing Plan LGS-13
Large General Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. The minimum monthly billing demand hereunder is 200 kW. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge and minimum bill	$371.88 per month
Demand Charge	$ 10.352 per kW

Energy Charges: All energy charges below are charged on a per kWh basis.

Delivery Charge	
Summer	$0.025656
Winter	$0.023910
Base Power Supply Charge	
Summer	$0.032554
Winter	$0.025054

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with Rider-1 PPFAC to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BILLING DEMAND
The maximum 15 minute measured demand in the month, but not less than 50% of the maximum demand used for billing purposes in the preceding 11 months, nor less than the contract demand, nor less than 200 kW.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

(b) When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

(c) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

The Company may require a written contract and a minimum term of contract.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$223.138 per month
Meter Reading	$ 18.594 per month
Billing & Collection	$111.564 per month
Customer Delivery	$ 18.594 per month
Demand Charge (kW):	
Generation Capacity	$6.911 per kW
Transmission	$2.685 per kW
Transmission Ancillary Services	
System Control & Dispatch	$0.036 per kW
Reactive Supply and Voltage Control	$0.143 per kW
Regulation and Frequency Response	$0.139 per kW
Spinning Reserve Service	$0.377 per kW
Supplemental Reserve Service	$0.061 per kW

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Pricing Plan LGS-13
Large General Service

Energy Charges (kWh):

Delivery Charge	
Summer	$0.012397 per kWh
Winter	$0.010651 per kWh
Generation Capacity	$0.009523 per kWh
Fixed Must-Run	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Base Power Supply Charge	
Summer	$0.032554 per kWh
Winter	$0.025054 per kWh

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Commonwealth of Virginia
Schedule 6VA

LARGE GENERAL SERVICE

I. APPLICABILITY

This schedule is applicable only to Customers electing to receive 50 kW or more of Electricity Supply Service and Electric Delivery Service from the Company for miscellaneous light and power service.

II. 30-DAY RATE

A. Distribution Service Charges

1. Basic Customer Charge
   Basic Customer Charge $75.37 per billing month.

2. Plus Distribution Demand Charge

First 700 kW of Distribution Demand	@	$ 1.295 per kW
Next 4300 kW of Distribution Demand	@	$ 1.036 per kW
Additional kW of Distribution Demand	@	$ 0.894 per kW

3. Plus rkVA Demand Charge @ $ 0.16 per rkVA

B. Electricity Supply (ES) Service Charges

1. Generation Demand Charge
   All kW of ES Demand @ $ 9.006 per kW

2. Plus Generation Adjustment Demand Charge

First 700 kW of Demand	@	$ 0.081 per kW
Next 4300 kW of Demand	@	$ 0.065 per kW
Additional kW of Demand	@	$ 0.055 per kW

3. Plus Generation kWh Charge

First 24,000 ES kWh	@	1.302¢ per kWh
Next 186,000 ES kWh*	@	0.672¢ per kWh
Additional ES kWh	@	0.271¢ per kWh

*If Electricity Supply Demand is 1000 kW or more, add 210 kWh for each Electricity Supply kW of Demand over 1000 kW.

(Continued)

II. 30-DAY RATE (Continued)

4. Plus each Electricity Supply kWh used is subject to all applicable riders.

C. The minimum charge shall be such as may be contracted for, but not less than the sum of charges in A. and B, above.

III. DETERMINATION OF DISTRIBUTION DEMAND

The Distribution Demand shall be billed only where the service voltage is less than 69 kV. The kW of demand billed under II.C. shall be such as may be contracted for, but not less than the higher of:

A. The highest average kW measured in any 30-minute interval during the current and preceding eleven billing months, or

B. 50 kW.

Any kW minimum amount or stated dollar minimum shall be determined in accordance with Paragraph V.F. of the Agreement.

IV. DETERMINATION OF RKVA DEMAND

The rkVA demand shall be billed only where the kW of demand is determined underV.B. The rkVA of demand billed shall be the highest average rkVA measured in any 30-minute interval during the current billing month.

V. DETERMINATION OF ELECTRICITY SUPPLY DEMAND

A. Except as provided under V.B., the kW of demand billed under II.B.1. shall be the highest of:

1. The highest average kW measured in any 30-minute interval during the current billing month, or

2. 90% of the highest average kW of demand measured at this location in any 30-minute interval during the billing months of June through September of the preceding eleven billing months, or

(Continued)

V. DETERMINATION OF ELECTRICITY SUPPLY DEMAND (Continued)

3. 50 kW.

B. Where the kW of demand determined under V.A. is 1000 kW or more, the kW of demand billed under II.B.1. shall be the highest of:

1. The highest average kW measured in any 30-minute interval of the current billing month during the on-peak hours of:

   a. 10 a.m. to 10 p.m., Mondays through Fridays, for the billing months of June through September.

   b. 7 a.m. to 10 p.m., Mondays through Fridays, for all other billing months.

2. 90% of the highest kW of demand at this location as determined under V. B. 1., above during the billing months of June through September of the preceding eleven billing months, or

3. 1000 kW.

VI. DETERMINATION OF ELECTRICITY SUPPLY ADJUSTMENT DEMAND

The kW of demand billed under Paragraph II.B.2. shall be the Distribution Demand determined under Paragraph III.

VII. METER READING AND BILLING

When the actual number of days between meter readings is more or less than 30 days, the Basic Customer Charge, the Distribution Demand Charge, the rkVA Demand Charge, the Generation Demand Charge, the Generation Adjustment Demand Charge, the quantity of kWh in the first two blocks of the Generation kWh Charge, and the minimum charge of the 30-day rate will each be multiplied by the actual number of days in the billing period and divided by 30.

(Continued)

VIII. SERVICE AVAILABLE

Normally the Company will supply the equipment necessary and will deliver to the Customer, in accordance with *The Amended and Restated Agreement for the Provision of Electric Service Restricted to Agencies of the Commonwealth Of Virginia*, at one Delivery Point mutually satisfactory to the Customer and the Company, 60 cycle alternating current electricity of the phase and voltage desired by the Customer at said Delivery Point, provided electricity of the phase and voltage desired by the Customer is available generally in the area in which electricity is desired.

IX. PARALLEL OPERATION SERVICE

A Customer operating an electric power plant in parallel with the Company's facilities may elect service under this schedule provided that suitable relays and protective equipment are furnished, installed, and maintained at the Customer's expense in accordance with specifications furnished by the Company. The relays and protection equipment shall be subject, at all reasonable times, to inspection by the Company's authorized representative.

X. STANDBY/MAINTENANCE SERVICE

A Customer operating an electric power plant who requires standby or maintenance service during times of power plant outage may elect service under this schedule provided the Customer contracts for the maximum kW which the Company is to supply. In case the maximum measured demand exceeds the contract demand, the contract demand shall be increased by such excess demand. The contract demand may be changed by mutual agreement as to the amount of change and term of agreement; however, in no case shall the contract demand be reduced below the maximum demand measured during the preceding eleven billing months. Where the service voltage is less than 69 kV, the demand billed under II.A.2. and II.B.2. shall be the contract demand.

XI. RATE SCHEDULE REVISION

This rate schedule is subject to revision from time to time as specified in Paragraph III.B. and III.G. of *The Amended and Restated Agreement for the Provision of Electric Service Restricted to Agencies of the Commonwealth of Virginia*.

Commonwealth of Virginia
Schedule 6VA

LARGE GENERAL SERVICE

(Continued)

XII. TERM OF CONTRACT

The term of contract for the purchase of electricity under this schedule shall be such as may be mutually agreed upon, but for not less than one year. During the term of contract, the customer may be billed on the corresponding Unbundled Rate Schedule, Schedule 6VAU, if applicable.

Wheat Belt Public Power District
Board of Directors

RATE SCHEDULE

Rate Schedule: E-2 HEAVY INDUSTRIAL AND COMMERCIAL COINCIDENTAL DEMAND RATE		
Original Issue Date: **5-23-1997**	Revision/Effective Date: **1-1-2010**	Page **1** of **2**

Qualifying Service

Any service, 1000 kVA or greater connected transformer capacity, delivered from the 12.5/7.2 or 24.9/14.4 kV distribution system.

or

Any service delivered from the 34.5 kV transmission system.

This rate is only available to customers who enter into a 10-year service agreement with Wheat Belt Public Power District.

Rates

Basic Charge:	$40.00 per month
Retail Demand Charge:	$7.76 per kW, per month
Generation Demand Charge:	$17.61 per kW, per month
Energy Charge:	$0.0396 per kWh

Determination of Billing Retail Demand

The billing Retail Demand shall be the maximum kilowatt (kW) demand established by the customer for any fifteen (15) consecutive minute period during the month for which the bill is rendered, as indicated or recorded by the District's metering equipment.

Determination of Billing Generation Demand

The billing Generation Demand shall be the maximum fifteen (15) minute integrated demand established by the customer during the current billing period coincident with the District's peak period total integrated system billing demand. The summer peak period is April thru September between 7:30 am and 10:00 pm. The winter peak period is October thru March between 6:00 am and 12:00 pm and between 5:00 pm and 10:30 pm.

Power Factor Charge

A power factor charge will be assessed to compensate for average power factor lower than ninety-five percent (95%) lagging. The power factor charge will be calculated by increasing the measured Retail Demand and Generation Demand by one percent (1%) for each one percent

(1%) by which the average power factor is less than ninety-five percent (95%) lagging. **If there is more than one metering facility and these facilities are aggregated into one equivalent billing, then the average power factor charge will be weighted based upon the kilowatt-hour usage of each facility.**

Minimum Monthly Charge

The minimum monthly charge shall be the highest of the following, as determined by the District:

- The monthly minimum billing amount as specified by contract between the District and the customer.
- $2.50 per kilowatt (kW) of maximum kW Retail Demand established during the eleven months prior to the current month.

Production Cost Adjustments

In the event that adjustments are made to the District's wholesale cost of power, charges or credits shall be made to this rate accordingly. Such charges or credits shall be billed separately as "Production Cost Adjustments." If changes are made to the wholesale supplier's power rate for the District, the District reserves the right to change this rate to reflect the wholesale supplier changes.

Payment Terms

Payment of an invoice is due upon receipt, and considered delinquent as of the last business day of the month. If payment is not received by the last business day of the month, one percent (1%) of the outstanding amount will be assessed as a finance charge, and the account will be subject to disconnection.

WYRULEC COMPANY
P.O. Box 359
Lingle, WY 82223

Sheet No. 8

LARGE POWER SERVICE GREATER THAN 350 kVa **LP - L**

APPLICABLE:

To all consumers served in the State of Wyoming requiring 350 kVa or more of transformer capacity; located on or near the Cooperative's three-phase lines for all types of commercial usage; subject to the established rules and regulations of the Cooperative.

CHARACTER OF SERVICE:

Three-Phase, 60 cycles, at standard voltages

RATE:

Basic Charge:	$200.00	per consumer per month
Retail Demand Charge:	$8.66	per month per kW of Retail Demand
Generation Demand Charge:	$23.65	per month per kW of Generation Demand
Energy Charge:	$0.0356	per month per kWh

Any adjustments to the base rate above shall be reflected on the Rate Rider Tariff - Sheet 14

DETERMINATION OF RETAIL DEMAND:

The Retail Demand shall be the maximum kilowatt (kW) established by the consumer for any thirty (30) consecutive minutes during the month for which the bill is rendered as indicated or recorded on a demand meter and adjusted for power factor as provided below.

DETERMINATION OF GENERATION DEMAND:

The Generation Demand shall be the maximum kilowatt (kW) established by the consumer for any thirty (30) consecutive minutes coincident with the wholesale supplier's generation billing demand during the month for which the bill is rendered as indicated or recorded on a demand meter and adjusted for power factor as provided below.

The wholesale supplier's generation billing demand shall be the Cooperative's highest thirty (30) minute integrated total demand measured in each monthly billing period during the wholesale supplier's Summer Peak Period or the Winter Peak Period. The generation billing demand shall be the maximum coincident peak demand for all of the Cooperative's points of delivery, the same as if the service were provided to the Cooperative at one point of delivery.

The wholesale supplier's Summer Peak Period is from 7:00 AM through 10:00 PM (the billing ½ hour period ending 7:30 AM through the billing ½ hour period ending at 10:00 PM) daily during the months of April through September. The wholesale supplier's Winter Peak Periods are from 5:30 AM through 12:00 PM (the billing ½ hour period ending 6:00 AM through the billing ½ hour period ending at 12:00 PM) and from 4:30 PM through 10:30 PM (the billing ½ hour period ending 5:00 PM through the billing ½ hour period ending 10:30 PM) daily during the months of October through March.

FILED
PUBLIC SERVICE COMMISSION
OF WYOMING

DEC 17 2008

Date Approved: November 20, 2008

Date Issued: November 20, 2008

Date Effective: January 1, 2009

By: Rollie Miller

Title: Executive VP/General Manager