

CRAIG-BOTETOURT ELECTRIC COOPERATIVE

Case No. PUE-2009-00065

**DIRECT TESTIMONY OF
MARTIN J. BLAKE**

November 2, 2009

1 **Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 **A:** My name is Martin J. Blake. My business address is The Prime Group, LLC,
3 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

4 **Q: BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?**

5 **A:** I am a Member and Principal of The Prime Group, LLC. The Prime Group
6 provides consulting services in the areas of strategic planning, rate and regulatory
7 support, and training for energy industry clients.

8 **Professional Qualifications & Experience**

9 **Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

10 **A:** I received my Ph.D. in Agricultural Economics in 1976 from the University of
11 Missouri, Columbia. My doctoral work centered on the areas of marketing and
12 econometrics. I also hold a Master of Arts in Economics from the University of
13 Missouri, Columbia, which I received in 1972. In addition, I received a Bachelor
14 of Arts degree in Economics from Illinois Benedictine College in 1970.

15 **Q: IN WHAT AREAS DOES YOUR PRACTICE CONCENTRATE?**

16 **A:** As a member of The Prime Group, I have provided utility clients with assistance
17 regarding rate design and development for both wholesale and retail rates; the
18 development of innovative rates to achieve strategic objectives; the unbundling of

1 rates and the development of menus of rate alternatives for use with customers;
2 performance-based rate and incentive rate development; state and federal
3 regulatory filing development, testimony and support; cost of service
4 development and support; strategic planning; and energy marketing and brokering
5 capability development. I have also been involved in the development of the
6 Midwest ISO and represent Southern Illinois Power Cooperative and Hoosier
7 Energy on the Midwest ISO Transmission Owners Committee, Transmission
8 Owners Tariff Working Group, and Demand Response Working Group. I have
9 made presentations to train account executives in sales and customer negotiation,
10 as well as presentations in ratemaking and utility finance seminars and workshops
11 regarding basic utility marketing. I have provided marketing and marketing
12 support services for utility clients and have assisted them in assessing their
13 marketing capabilities and processes.

14 **Q: PLEASE BRIEFLY SUMMARIZE YOUR AREAS OF PROFESSIONAL**
15 **EXPERIENCE PRIOR TO JOINING THE PRIME GROUP.**

16 **A:** I have professional experience as an economist and professor of economics, as a
17 utility regulator, and as a utility manager and executive.

18 **Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS AN**
19 **ECONOMIST.**

20 **A:** From January 1977 to December 1986, I was employed first as an Assistant
21 Professor, then as an Associate Professor, and finally as a Professor of
22 Agricultural Economics at New Mexico State University in Las Cruces, New
23 Mexico ("NMSU"). I was the head of the undergraduate program and taught

1 economics, agricultural economics and econometrics. While at NMSU, I also
2 worked as a consultant for various clients, providing price forecasting, load
3 forecasting, and marketing services. From 1992 through 1994, I taught
4 mathematical economics and econometrics as an Adjunct Professor in the
5 Economics Department at the University of Louisville. Prior to my joining the
6 faculty at NMSU, I served in the U. S. Army as an instructor of economics,
7 statistics, and accounting at the U. S. Army Institute of Administration at Fort
8 Benjamin Harrison, Indianapolis, Indiana.

9 I also have a variety of experience with the application of economics to utility
10 public policy issues. In addition to my experience as a utility regulator and
11 executive, which I describe below, I have, for example, taught retail and
12 wholesale pricing for electric utilities at the NARUC Annual Regulatory Studies
13 Program at Michigan State University since 1993. From May 1983 to August
14 1983, while on a sabbatical leave from NMSU, I served as a Policy Analyst for
15 the Assistant Secretary for Land and Water at the U. S. Department of Interior.

16 **Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A**
17 **UTILITY REGULATOR.**

18 **A:** From January 1987 to November 1990, I served as a Commissioner and as the
19 Chairman of the New Mexico Public Service Commission. As a Commissioner,
20 my duties included making policy and adjudicatory decisions regarding rates,
21 terms of service, financing, certificates of public convenience and necessity, and
22 complaints for electric, gas, water, and sewer utilities. As Chairman, I supervised
23 a staff of thirty-two professionals and sixteen support staff. During my tenure on

1 the New Mexico Commission, I also served as Chairman of the Western
2 Conference of Public Service Commissioners Electric Committee and as
3 Chairman of the Committee on Regional Electric Power Cooperation, a group
4 composed of state public service commissioners and representatives from the state
5 energy offices of the thirteen western states.

6 As a Commissioner, I interpreted legislation, reviewed prior Commission cases to
7 determine the precedents that they provided, drafted rules and regulations, wrote
8 Orders, conducted hearings, ruled on motions, and served as an arbitrator in
9 alternative dispute resolution proceedings. I performed adjudicatory and
10 regulatory functions for the four years that I served on the Commission.

11 **Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A**
12 **UTILITY MANAGER.**

13 **A:** From December 1990 to June 1996, I was employed by Louisville Gas and
14 Electric Company ("LG&E"). Initially, I served as LG&E's Director of
15 Regulatory Planning. In this position, I was responsible for coordinating all of
16 LG&E's state and federal regulatory efforts, and prepared and presented testimony
17 to regulators.

18 My areas of responsibility were expanded in April 1994 to include marketing and
19 strategic planning. As the Director, Marketing, Planning and Regulatory Affairs,
20 I was responsible for coordinating LG&E's retail gas and electric marketing,
21 strategic planning, and state and federal regulatory efforts. I continued to be
22 employed in that capacity at LG&E until June 1996, when I joined the Prime
23 Group as one of its Principals.

1 **Q: PLEASE DESCRIBE THE INDUSTRY GROUPS IN WHICH YOU HAVE**
2 **PARTICIPATED.**

3 **A:** I have served on several regional transmission coordination groups such as the
4 Interregional Transmission Coordination Forum, and the General Agreement on
5 Parallel Paths, as well as the following committees of the Edison Electric Institute
6 (“EEI”) -- Economics and Public Policy Executive Advisory Committee, Strategic
7 Planning Executive Advisory Committee, Transmission Task Force, and Power
8 Supply Policy Technical Task Force. Recently, I have worked with a group of
9 utilities developing the Midwest ISO and serve as Southern Illinois Power
10 Cooperative’s and Hoosier Energy’s representative on the Transmission Owner
11 Committee, Tariff Committee and Demand Response Working Group. I am
12 currently Chairman of the Midwest ISO Transmission Owners Tariff Committee.

13 **Q: HAVE YOU TAUGHT ANY COURSES OR SEMINARS IN THE AREA**
14 **OF UTILITY RESTRUCTURING?**

15 **A:** Yes. I have taught the following courses at the NARUC Annual Regulatory
16 Studies Program at Michigan State University: 1) retail ratemaking, 2) wholesale
17 pricing, 3) rate of return regulation, 4) competitive market fundamentals, 5)
18 electric industry overview, 6) the economics of power production and delivery, 7)
19 electric system technologies, and 8) the institutions and organizations of the new
20 electric utility industry. Each year, I also teach and conduct numerous workshops
21 and programs and deliver invited presentations to utility managers and regulators
22 on a variety of subjects.

23 **Q. IN WHAT CASES HAVE YOU PREVIOUSLY TESTIFIED?**

1 A. I have testified in numerous proceedings before the Federal Energy Regulatory
2 Commission and various state regulatory bodies. I recently testified before this
3 Commission on behalf of Northern Neck Electric Cooperative in Case No. PUE-
4 2008-00076. Attachment MJB-1 is a summary of the testimony that I have
5 presented in other regulatory proceedings.

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

8 A. The Prime Group was retained by Craig-Botetourt Electric Cooperative (“C-
9 BEC” or “the Cooperative”) to provide assistance with calculating a revenue
10 requirement, performing a cost of service study, providing assistance with
11 designing new rates and providing assistance in reviewing and modifying the
12 Terms and Conditions of Service. The purpose of my testimony is to describe the
13 rate design that was utilized in this proceeding and describe how the Terms and
14 Conditions of Service were modified.

15 **Q. WHAT SCHEDULES AND EXHIBITS ARE YOU SPONSORING IN THIS**
16 **PROCEEDING?**

17 A. I am sponsoring the following Schedules filed by C-BEC pursuant to Appendix A
18 of the Virginia State Corporation Commission’s regulations 20 VAC 5-200-21:

- 19 Schedule 5A – Proposed Rates and Tariffs
- 20 Schedule 5B – Revenue Allocation
- 21 Schedule 6 – Sample Billing
- 22 Schedule 14A – Reconstruction of Test Year Billing Units

23 I am also sponsoring the following attachments to my testimony:

1 Attachment 1 – Prior Testimony of Dr. Martin J. Blake

2 Attachment 2 – Sample Communication to Customers

3 **Q. WHAT WERE THE RATEMAKING OBJECTIVES IN DEVELOPING**
4 **THE PROPOSED RATES?**

5 **A.** In general, we tried to develop rates that more closely reflect the cost of providing
6 service. One of our key objectives was to bring the rates of return more in line by
7 allocating relatively more of the revenue increase to the customer classes with low
8 rates of return and allocating relatively less of the revenue increase to the
9 customer classes with high rates of return. We chose not to decrease the revenue
10 collected from any class, even though certain customer classes show high rates of
11 return that could justify such reductions. For example, the cost of service study
12 indicated rates of return of 38.88% and 13.37% for the Commercial and Large
13 Power Service and Outdoor Lighting classes, respectively. Therefore, for these
14 classes, we developed rates that allocated less of the overall increase to these two
15 classes. On the other extreme, we mitigated the level of increase to the
16 Residential Service class by not reducing the revenue collected from classes with
17 high rates of return relative to the total system rate of return. A higher increase
18 could have been supported for the Residential Service class if the revenue
19 collected from other classes had been reduced.

20 Another key objective was to bring the unit charges more in line with the unit
21 costs derived from the cost of service study. The Cooperative's rates include both
22 two-part rates, consisting of a Consumer Delivery Charge and energy charge, and
23 three-part rates, consisting of a Consumer Delivery Charge, energy charge, and

1 demand charge. We worked to develop rates that moved these various charges
2 toward the unit costs indicated by the cost of service study.

3 **Q. WHAT WAS THE BASIC UNDERLYING INFORMATION THAT**
4 **SUPPORTED THE PROPOSED ALLOCATION OF THE REVENUE**
5 **REQUIREMENT AMONG C-BEC'S RATE CLASSES?**

6 **A.** The cost of service study provided information measuring the extent to which the
7 revenues generated by each customer class contribute to the overall return earned
8 by C-BEC. As shown on Schedule 7, Attachment B, page 10, the cost of service
9 study indicated that the rate of return for individual classes ranged between 0.55%
10 and 38.88% for jurisdictional customers, as compared to an overall pro forma
11 adjusted actual return on rate base of 1.57% for jurisdictional customers, with the
12 rate of return for Residential Service being the lowest and the rate of return for
13 Commercial and Large Power Service being the highest. This indicates a need to
14 increase the revenues collected from some classes more than others. For example,
15 the rate components for the Commercial and Small Power Service rate, the
16 Commercial and Large Power Service and the Outdoor Lighting rate were
17 redesigned to more accurately reflect cost causation, but because they have a rate
18 of return significantly higher than the average, relatively less of the rate increase
19 was collected from these three classes of customers. Even though the
20 Commercial and Large Power Service as a whole received a relatively small
21 increase, customers within this class may experience an increase in their energy
22 bills because of their usage patterns. The same is true in the Residential Service
23 and Commercial and Small Power Service classes because of the significant

1 changes in rate design in these classes. Not decreasing the revenue collected from
2 the Outdoor Lighting and the Commercial and Large Power Service classes is
3 consistent with the principle applied by the C-BEC Board that if some customer
4 classes are getting an increase, no customer class should receive a decrease.

5 **Q. AFTER CONSIDERING ALL OF THE REQUIRED PRO-FORMA**
6 **ADJUSTMENTS, WHAT IS THE PROPOSED INCREASE IN REVENUES**
7 **AND HOW IS THE INCREASE APPORTIONED TO THE INDIVIDUAL**
8 **CUSTOMER CLASSES?**

9 **A.** In this filing, C-BEC is proposing to increase its annual revenues to its
10 jurisdictional customers by \$1,468,716 as shown on page 1 of Schedule 5B.
11 Schedule 5B shows that the proposed rate increases would result in a 14.9%
12 increase in annual revenues paid by jurisdictional consumers. In addition to
13 requesting an increase in electric service rates, C-BEC also is proposing to revise
14 its Terms and Conditions for Electric Distribution Service, to change its fees so
15 that they more accurately reflect the cost of providing the services for which the
16 fees are assessed, and to change its line extension policy.

17 The proposed rates apportion the revenue increase among the jurisdictional
18 customer classes. As shown on pages 2 through 5 of Schedule 5B, the increase in
19 revenues for each rate class was determined by applying both the current and
20 proposed charges to the adjusted billing determinants for each rate class.

21 **Q. HAVE YOU PREPARED AN EXHIBIT RECONSTRUCTING C-BEC'S**
22 **TEST-YEAR BILLING UNITS?**

1 A. Yes. In order to develop C-BEC's proposed rates it was necessary to reconstruct
2 test-year billing determinants. The reconstruction of C-BEC's billing
3 determinants is shown on Schedule 14A. As shown on page 1 of Schedule 14A,
4 the total of the revenues were within -0.06% of the Cooperative's actual total
5 revenues. The reconciliation of the billing units for the individual rates are
6 calculated on pages 2 through 5 of Schedule 14A. Furthermore, the largest
7 percentage difference between calculated and reported revenues for any rate class
8 was -4.0% for the Outdoor Lighting class, which represented a difference of
9 \$3,379, thus confirming the accuracy of the test period billing units.

10 **Q. DO C-BEC'S RATES INCLUDE A WHOLESALE POWER COST**
11 **ADJUSTMENT?**

12 A. Yes. C-BEC utilizes a wholesale power cost adjustment that accounts for changes
13 in its purchased power costs from its power suppliers. The Cooperative is not
14 proposing to change the way that the wholesale power adjustment charge
15 operates. However, C-BEC is proposing to properly allocate the costs currently
16 collected through the wholesale power adjustment and to initially reset the
17 wholesale power adjustment charge to zero.

18 **Q. WHAT IS THE PROPOSED REVENUE INCREASE FOR SCHEDULE RS-**
19 **10-U, RESIDENTIAL SERVICE?**

20 A. C-BEC is proposing a revenue increase of \$1,405,183, or 17.7%, for the
21 Residential Service rate class. An increase of this magnitude is necessary to move
22 this rate class more in the direction of equalized rates of return based on the low

1 rate of return on the Residential Service class relative to other rate classes as
2 indicated in the cost of service study in Schedule 7.

3 **Q. WHAT ARE THE MOST SIGNIFICANT CHANGES C-BEC IS**
4 **PROPOSING REGARDING THE COST STRUCTURE FOR SCHEDULE**
5 **RS-10-U?**

6 **A.** The Cooperative is proposing changes in the Consumer Delivery Charge, the rate
7 structure of Schedule RS-10-U, and to reset the wholesale power cost adjustment.
8 As shown on Schedule 7, Attachment B, page 20, the cost of service study
9 indicates that the customer cost for the residential class should be \$31.63 per
10 customer per month, so C-BEC is proposing to increase the monthly Residential
11 Consumer Delivery Charge from \$14.00 to \$31.63 per customer per month to
12 reflect more accurately the cost of providing service. C-BEC also is proposing to
13 eliminate the declining block rate structure for Residential Service, and proposes
14 to unbundle the energy charge into a purchased power demand charge of 3.062
15 cents per kWh, a purchased power energy charge of 3.658 cents per kWh, and a
16 distribution demand charge assessed on a kWh basis of 3.957 cents per kWh, for a
17 total energy charge of 10.677 cents per kWh. Finally, although it would initially
18 be reset to zero, the Wholesale Power Cost Adjustment Charge would be assessed
19 in the future as actual wholesale purchased power costs deviated from the
20 purchased power costs included in base rates.

21 **Q. PLEASE EXPLAIN HOW THE CONSUMER DELIVERY CHARGE WAS**
22 **CALCULATED FOR SCHEDULE RS-10-U, RESIDENTIAL SERVICE.**

1 A. The monthly Consumer Delivery Charge for Residential Service was calculated
2 by adding the monthly customer-related unit costs and monthly customer-related
3 unit margins derived from the cost of service study. The monthly customer-
4 related unit costs were calculated by dividing the total customer-related costs for
5 the Residential Service class by the number of customer months for that class in
6 the test year. The result was a monthly customer-related unit cost of \$22.23 per
7 customer per month for the Residential Service class, as shown on page 20 of
8 Schedule 7, Attachment B. The unit margins assigned for collection through the
9 monthly Consumer Delivery Charge were calculated by allocating the total
10 margins assigned to the Residential Service class into distribution demand-related
11 and customer-related components, based on the percentage of the net cost rate
12 base that was customer related or demand related for the Residential Service
13 class, and dividing the allocated customer-related margins by the number of
14 customer months in the test year for the Residential Service class. The result was
15 a customer-related unit margin of \$9.40 per customer per month. Adding the
16 monthly customer-related unit costs and monthly customer-related unit margins
17 results in a Consumer Delivery Charge of \$31.63, as shown on Schedule 7,
18 Attachment B, page 20.

19 **Q. DOES THE CURRENT CONSUMER DELIVERY CHARGE OF \$14.00**
20 **ADEQUATELY RECOVER CUSTOMER-RELATED COSTS FOR THE**
21 **RESIDENTIAL CLASS?**

22 A. No. The current Consumer Delivery Charge of \$14.00 per customer per month
23 does not even recover all of the customer-related costs, let alone any of the

1 margins that would normally be assigned for collection through the Consumer
2 Delivery Charge. Based on calculations from the cost of service study, there are
3 about \$8.23 in fixed cost per customer per month (calculated as $\$22.23 - \$14.00 =$
4 $\$8.23$) and \$9.40 in margins per customer per month that are not being collected
5 through the Consumer Delivery Charge, for a total of \$17.63 per customer per
6 month that is not being recovered through the Consumer Delivery Charge. When
7 this under-recovery of \$17.63 per customer per month is multiplied by the 70,572
8 customer months for the Residential Service class during the test year, shown on
9 page 2 of Schedule 5B, the result is \$2,232,192 in fixed cost and margin that is
10 not being recovered as it should be, through the Consumer Delivery Charge.

11 **Q. HOW IS THAT REVENUE CURRENTLY BEING COLLECTED?**

12 **A.** It is currently being collected through the energy charge instead of the Consumer
13 Delivery Charge, resulting in about 3.35 cents per kWh of fixed cost and margin
14 being shifted to the energy charge (calculated as $\$2,232,192 / 66,609,182 \text{ kWh} =$
15 $\$0.0335$). Thus, the Consumer Delivery Charge is \$17.63 per customer per month
16 too low and the energy charge is 3.35 cents per kWh too high. This recovery of
17 fixed costs and margins through the energy charge results in intra-class subsidies.

18 **Q. PLEASE EXPLAIN THESE INTRA-CLASS SUBSIDIES.**

19 **A.** If fixed costs are recovered through variable charges, each kWh contains a
20 component of fixed costs and margins and customers using more energy than the
21 average customer in the class are paying more than their fair share of fixed costs
22 and margins, while customers using less energy than the average customer in the
23 class are paying less than their fair share of fixed costs and margins. Collecting

1 fixed costs through the energy charge typically results in customers with above-
2 average usage subsidizing customers with below-average usage, which is the
3 intra-class subsidy to which I was referring above. The collection of variable
4 costs through fixed charges also results in an intra-class subsidy, with customers
5 with below-average usage subsidizing customers with above-average usage.

6 **Q. WHAT IS THE BEST WAY TO ELIMINATE THESE INTRA-CLASS**
7 **SUBSIDIES?**

8 **A.** Intra-class subsidies result when inappropriate cost drivers are applied to the
9 recovery of costs. Fixed costs and margins should be collected through the billing
10 units associated with the appropriate cost driver, and energy usage clearly is not
11 the correct cost driver for fixed costs. The rate making principle that should be
12 followed to avoid intra-class subsidies is that fixed costs should be recovered
13 through fixed charges (such as the Consumer Delivery Charge and demand
14 charge) and variable costs should be recovered through variable charges (such as
15 the energy charge and the wholesale power cost adjustment charge). In order to
16 eliminate this source of intra-class subsidies, C-BEC wants to pursue a rate design
17 that generally recovers fixed costs through fixed charges and variable costs
18 through variable charges.

19 **Q. WHAT IMPACT WOULD INCREASING THE CONSUMER DELIVERY**
20 **CHARGE AND REDUCING THE ENERGY CHARGE HAVE ON THE**
21 **AVERAGE CUSTOMER?**

22 **A.** Rates are averages; therefore, any rate design that was revenue neutral would
23 have no impact on a customer with a usage equal to the class average. If the rate

1 design change is revenue neutral, increasing the Consumer Delivery Charge from
2 \$22.23 per customer per month and reducing the energy charge by 3.35 cents per
3 kWh would have no impact on the average customer. The impact on customer
4 energy bills would be greatest at the extremes of very low energy usage and very
5 high energy usage. The change would result in higher energy bills for low-usage
6 customers, as the subsidy that they had been receiving was removed, and lower
7 energy bills for high-usage customers as the subsidies that they had been paying
8 were eliminated.

9 **Q. TYPICALLY, WHO ARE THE LOW-USAGE CUSTOMERS WHO**
10 **WOULD BE PAYING HIGHER ENERGY BILLS ONCE THE SUBSIDIES**
11 **WERE REMOVED?**

12 **A.** For most rural electric cooperatives, the low-usage customers are loads like boat
13 docks, garages, electric fences, stock tanks, vacation homes, hunting camps,
14 fishing camps, and services run to barns in case they might be needed. All of
15 these loads typically consume very few kilowatt hours during the course of a year
16 and the usage is sporadic. However, the cooperative often incurs significant fixed
17 costs in installing the minimum system requirements necessary to serve these
18 loads. These loads are often located far from roads and existing distribution lines.
19 A rate design with a low Consumer Delivery Charge and with a significant
20 portion of fixed cost and margins recovered through the energy charge produces
21 insufficient revenue to support the investment necessary to serve loads such as
22 vacation homes, barns, stock tanks, electric fences, and hunting cabins. This

1 inappropriate rate design results in these customers being subsidized by the other
2 cooperative customers who have above-average usage.

3 The members of the Cooperative's board of directors, who are both members and
4 customers of the Cooperative, do not believe that this is appropriate. A rate
5 design with a low Consumer Delivery Charge and with a significant portion of the
6 Cooperative's fixed cost and margins recovered through the energy charge sends
7 improper economic signals to customers. It sends a signal that it is relatively
8 inexpensive to provide the minimum amount of physical equipment necessary to
9 provide service to customers. This is definitely not the case, especially in rural
10 areas.

11 **Q. HOW WOULD A CHANGE IN THE CONSUMER DELIVERY CHARGE**
12 **AND ENERGY CHARGE AFFECT FIXED AND LOW INCOME**
13 **CUSTOMERS?**

14 **A.** Fixed and low income customers only benefit from a rate design with a lower
15 Consumer Delivery Charge and higher energy charge than a cost of service study
16 indicates is appropriate if they have an energy usage that is lower than the class
17 average. Generally, we find this is not the case for low income customers. The
18 housing stock that many low income customers are living in is relatively
19 inefficient from an energy usage standpoint, so their energy usage is frequently
20 *above* the class average. This inefficient energy usage of the dwelling in which
21 they live is one factor in the price of the dwelling being discounted to a level that
22 low income customers can afford. The impact of a higher Consumer Delivery
23 Charge and reduced energy charge is usually greatest on low energy users, and

1 low and fixed income customers are not typically low energy users. They
2 typically have higher than average energy usage and, because of their higher
3 usage, are currently helping to subsidize low usage customers. In truth, with the
4 elimination of this subsidy, the typical low income customer would actually
5 benefit from a rate design that had a higher Consumer Delivery Charge and a
6 lower energy charge.

7 In addition, for fixed income customers, it is my experience that, because they
8 have a stock of appliances similar to other customers and tend to spend more time
9 at home, these customers generally have usage levels in the neighborhood of the
10 class average and would not be significantly affected by the proposed change.

11 **Q. IS THE C-BEC BOARD CONCERNED ABOUT THE NUMBER OF**
12 **COMPLAINTS THAT MIGHT ARISE FROM IMPLEMENTING A**
13 **HIGHER CONSUMER DELIVERY CHARGE AND A REDUCED**
14 **ENERGY CHARGE?**

15 **A.** Since they are customers themselves and are elected by their fellow customers,
16 the directors on C-BEC's board are very sensitive to complaints and are
17 concerned about the complaints that they might receive as a result of
18 implementing a higher Consumer Delivery Charge while reducing the energy
19 charge.

20 **Q. WHAT CAN BE DONE TO HELP MITIGATE THE NUMBER OF**
21 **COMPLAINTS?**

22 **A.** I believe that customer education is the key to avoiding customer complaints.
23 Complaints can best be mitigated through an effective communication plan.

1 C-BEC needs to communicate to its members that the Consumer Delivery Charge
2 reflects the cost of installing and maintaining the minimum amount of equipment
3 necessary to provide a customer with grid access, and that the current Consumer
4 Delivery Charge is being changed as a matter of fairness to eliminate subsidies
5 among customers that currently exist. The Cooperative also can put the new
6 Consumer Delivery Charge into perspective by comparing it to the cost for other
7 basic utility services. In the counties served by the Cooperative, the charges for
8 basic utility services, with no premium services included, are as follows:

- 9 1. Basic telephone service ranges from \$22.99 to \$30.02;
- 10 2. Basic cable service ranges from \$29.99 to \$59.95;
- 11 3. Basic satellite dish service ranges from \$14.98 to 29.99;
- 12 4. Water & Sewer service ranges from \$35.00 to \$70.00; and
- 13 5. Internet service ranges from \$12.95 for dial up to \$49.99 for fiber optic.

14 These basic charges for each of these services are similar to or higher than the
15 proposed Consumer Delivery Charge for electric service. An example of the type
16 of customer communications that C-BEC may use is included as Attachment
17 MJB-2 to this testimony.

18 **Q. WOULD AN INVESTOR-OWNED UTILITY COST OF SERVICE STUDY**
19 **SUPPORT AN ACCESS CHARGE SIMILAR TO THAT PROPOSED BY**
20 **THE COOPERATIVE?**

21 **A.** No, I doubt that it would, because of the disparity in the relative number and
22 density of customers. The reason for the significant difference in monthly
23 customer charges between an investor-owned utility and a cooperative is that a

1 cooperative does not have as many customers as an investor-owned utility over
2 which to spread its fixed costs, resulting in a higher access charge for the
3 cooperative. As an example, assume that a mile of single-phase distribution line
4 costs \$30,000 to construct. The cost of the poles and wire are the same in a rural
5 area as they are in an urban area. However, in a rural area, a cooperative such as
6 C-BEC can spread this cost over only about 6 customers per mile of line, as
7 compared to a typical investor-owned utility that would spread this cost over
8 somewhere between 35 and 50 customers per mile of line.

9 By way of illustration, the following table provides a calculation of a comparative
10 annual revenue requirement for C-BEC and for Dominion Virginia Power for one
11 mile of distribution line, using a carrying charge of 15%:

| Utility | Cost/mile of distribution line | Customers/mile | Cost/customer |
|--------------------------------------|--------------------------------|----------------|---------------|
| Dominion Virginia Power | \$30,000 | 36 | \$125 |
| Craig-Botetourt Electric Cooperative | \$30,000 | 6 | \$750 |

12 This shows that the revenue requirement per customer would be much higher for
13 the Cooperative, resulting in a higher Customer Delivery Charge for the
14 Cooperative. The key to the difference in Customer Delivery Charges can
15 generally be traced to differences in customer density per mile of line, which
16 provides an indication of how far a utility can spread its fixed costs.

17 **Q. PLEASE DESCRIBE THE PROPOSED CHANGE IN C-BEC'S RATE**
18 **DESIGN FOR SCHEDULE RS-10-U, RESIDENTIAL SERVICE.**

1 A. C-BEC's current rate design has a declining block rate structure with the first 250
2 kWh having a Energy Delivery Charge of 6.082 cents per kWh, an Energy
3 Delivery Charge of 4.532 cents per kWh for the next 500 kWh and an Energy
4 Delivery Charge of 2.232 cents per kWh for all usage above 750 kWh, plus an
5 average wholesale power cost adjustment charge of 1.125 cents per kWh added to
6 the energy charge in each of these energy usage blocks. The proposed rate design
7 will eliminate the declining block rate structure and will price all kWh at 10.677
8 cents per kWh, with 3.062 cents per kWh collected through the purchased power
9 demand charge, 3.658 cents per kWh collected through the purchased power
10 energy charge and 3.957 cents per kWh collected through the distribution demand
11 charge. As mentioned earlier, the wholesale power cost adjustment charge would
12 initially be reset to zero.

13 **Q. WOULD THE PROPOSED HIGHER CONSUMER DELIVERY CHARGE**
14 **AND REDUCED ENERGY CHARGE SEND THE WRONG SIGNALS**
15 **FOR ENERGY CONSERVATION?**

16 A. No, in fact a rate design with a flat energy charge provides a stronger incentive to
17 pursue energy conservation than the existing declining block rate design. The
18 reason for the existing declining block rate design is that, since a significant
19 portion of the Cooperative's fixed costs and all of its margins are recovered
20 through an energy charge, the Cooperative wants the early usage blocks to
21 quickly recover as much of this fixed cost and margin as possible, through a
22 higher charges for these initial blocks. From a mathematical standpoint this
23 declining block rate structure is supportable because when a fixed cost is divided

1 by ever increasing amounts of usage, the result is a continually declining curve
2 that asymptotically approaches the horizontal axis. A declining block rate
3 structure is a discrete approximation of this continually declining curve that
4 asymptotically approaches the horizontal axis.

5 **Q. WHAT EFFECT DOES THE CURRENT RATE STRUCTURE HAVE ON**
6 **C-BEC'S ATTITUDE ABOUT ENERGY CONSERVATION?**

7 **A.** With a significant portion of fixed cost and all of its margins recovered through
8 the energy charge, it is difficult for the Cooperative to get enthusiastic about
9 energy conservation. Every kWh that is reduced also reduces the Cooperative's
10 fixed cost and margin recovery. When fixed costs and margins are recovered
11 through the Consumer Delivery Charge, as they should be (and as we now
12 propose), it is much easier for the Cooperative to get enthusiastic about helping
13 customers to reduce energy consumption, as the fixed cost and margin that
14 formerly were being lost when kWh usage was reduced is now being recovered
15 through the Customer Delivery Charge.

16 **Q. DOES A COST-BASED ACCESS CHARGE HAVE AN EFFECT ON NET**
17 **METERING?**

18 **A.** Yes. There is currently an increasing interest in customer-owned renewable
19 generation, such as wind and solar generation. This has resulted in regulatory
20 commissions and state legislatures requiring utilities to offer net metering to
21 customers with renewable generation. In fact, this Commission considered
22 revisions to its net energy metering rules, in Case No. PUE-2008-00008. With a

1 cost-based access charge, net metering will impose less of a financial burden on
2 the Cooperative.

3 **Q. PLEASE EXPLAIN.**

4 **A.** As the Commission is aware, with net metering, a customer's production of
5 energy using renewable generation technologies and the customer's energy
6 consumption are measured using a single meter, with the meter running backward
7 when the customer produces more energy than he is consuming. When C-BEC
8 sells power to a net metering customer, the Cooperative is providing three
9 services: 1) generation, 2) transmission, and 3) distribution. However, when a net
10 metering customer sells power to C-BEC, the customer is providing only a
11 generation service, as he does not own the transmission and distribution assets
12 needed for service. With net metering, when the customer produces more energy
13 than he is consuming and the meter is running backward, the customer receives
14 essentially the full retail energy charge for the excess energy produced, which
15 amount includes both a charge for transmission service and for distribution
16 service. Being paid the full retail energy charge represents a subsidy to the net
17 metering customer, a subsidy paid by other customers of the Cooperative who
18 either choose not to or cannot afford to own their own generators.

19 **Q. HOW WOULD THE COOPERATIVE RESPOND IN THIS SITUATION?**

20 **A.** With the customer receiving a subsidy when paid the full retail energy charge, and
21 because this subsidy can be large when significant amounts of fixed cost and
22 energy are included in the energy charge, a cooperative must limit the amount of
23 renewable energy served under a net metering tariff in order to avoid financial

1 harm. In effect, with its current rate design, C-BEC would be paying out fixed
2 cost and margin to net metering customers rather than recovering them. This
3 harm can be mitigated by removing the fixed cost and margin recovery from the
4 energy charge and putting it in the Consumer Delivery Charge where it belongs.
5 With a cost-based Customer Delivery Charge, net metering is much less of a
6 problem for a cooperative and the need for limits is much less significant.

7 **Q. PLEASE EXPLAIN WHY THE FIXED COST OF THE COOPERATIVE'S**
8 **DISTRIBUTION SYSTEM IS ALLOCATED INTO A CUSTOMER-**
9 **RELATED COMPONENT AND A DEMAND-RELATED COMPONENT.**

10 **A.** In order to be as fair as possible to all customers and so that customers will only
11 have to pay for what they actually use, the fixed cost of the Cooperative's
12 distribution system is divided into two components: 1) customer-related costs and
13 2) demand-related costs. The portion classified as customer-related cost is the
14 portion of the fixed costs of the distribution system that is size invariant, meaning
15 that it does not change relative to energy consumption. This size invariant portion
16 of the costs is usually determined using the zero-intercept approach, as it was in
17 the cost of service study submitted as Schedule 7 in this proceeding. Costs that
18 vary with the load carrying capability of the distribution facilities are size-related
19 and should be allocated on the basis of demand.

20 **Q. WHAT ABOUT DISTRIBUTION COSTS THAT DO NOT VARY WITH**
21 **THE LOAD THAT THE CUSTOMER PLACES ON THE SYSTEM?**

22 **A.** Costs that do not vary with the load carrying capability of the distribution
23 facilities are fixed costs that exist irrespective of what size of facility is installed.

1 These costs are present due to the fact that a customer is being served and will not
2 increase or decrease with the load requirements of that customer. Using
3 conductor as an example, there is a level of fixed production cost associated with
4 every conductor size. That fixed cost is best allocated on the basis of customer
5 months because it is caused by the existence of a customer, not by the existence of
6 the customer's demand. These costs that do not vary with the size of the
7 equipment are properly classified as customer costs and allocated based on the
8 number of customers in a class. The size invariant component is basically the
9 minimum system that any customer needs in order to have access to the electric
10 grid, while the costs that vary with size acknowledge that not all customers can
11 get by with just a minimum system. By making the split between customer-
12 related and demand-related components, it is possible for customers who only
13 need a minimum system and little else to be charged just for the minimum system,
14 while customers who need more than a minimum system can be charged for a
15 minimum system as well as the equipment that the customer needs that is related
16 to the demands that the customer places on the system. By ensuring that
17 customers only pay for what they need, the Cooperative is trying to be as fair as
18 possible to all of its customers.

19 **Q. IS THE PORTION OF THE COOPERATIVE'S DISTRIBUTION COSTS**
20 **THAT ARE CLASSIFIED AS DEMAND-RELATED STILL BEING**
21 **RECOVERED THROUGH KWH SALES FOR CUSTOMERS TAKING**
22 **RESIDENTIAL SERVICE?**

1 A. Yes. The portion of the cost of distribution facilities that is related to size and that
2 is classified as demand-related is recovered through a kWh charge for Residential
3 Service customers. Technically, this distribution demand charge should be
4 recovered through a non-coincident peak demand charge. However, since watt-
5 hour meters are less expensive than demand meters and because there are such a
6 large number of Residential Service customers, the distribution demand charge
7 has been collected through a kWh charge for Residential Service customers. This
8 results in a portion of the Cooperative's distribution demand-related fixed costs
9 and margins still being collected through an energy charge. However, this fixed
10 cost and margin recovery through the distribution demand component of energy
11 charge is a much smaller problem if the Cooperative sets the Consumer Delivery
12 Charge at a level that fully reflects customer related costs in the cost of service
13 study and correspondingly reduces the amount collected through the distribution
14 demand component of the energy charge for Residential Service customers.
15 Furthermore, since both the demand charge and the Consumer Delivery Charge
16 are regarded as fixed charges, the recovery of the customer-related component
17 through a Consumer Delivery Charge and the demand-related component through
18 a demand charge is consistent with the principle that fixed costs should be
19 recovered through fixed charges.

20 **Q. COULD ALL OF THE COOPERATIVE'S FIXED COSTS AND MARGIN**
21 **BE COLLECTED THROUGH THE CONSUMER DELIVERY CHARGE?**

22 A. Yes, but I wouldn't recommend it. Collecting all fixed costs and margin through
23 the Consumer Delivery Charge is known as a "straight fixed variable" rate design.

1 This rate design evolved from natural gas pipeline rate designs that recovered all
2 fixed costs and margins through a fixed charge and all variable costs through a
3 volumetric charge. If C-BEC utilized a straight fixed variable rate design, the
4 charge per customer per month would be \$83.07 per customer per month
5 (calculated as $\$5,862,082 / 70,572$ customer months = \$83.07 per customer per
6 month). Since a portion of C-BEC's distribution demand costs are related to the
7 amount of demand that customers place on the system, recovering all of the
8 distribution costs through a Consumer Delivery Charge would result in customers
9 who place small demands on the system subsidizing customers who place large
10 demands on the system. Making the distinction between distribution costs that
11 are related to capacity usage (volumetric) and distribution costs that are not
12 related to capacity usage (non-volumetric) produces as fair a result as possible to
13 customers with both small and large usages of distribution capacity. The non-
14 volumetric costs are recovered through a Consumer Delivery Charge and the
15 volumetric costs are recovered through a distribution demand charge.

16 **Q. DID THE C-BEC BOARD OF DIRECTORS PASS A RESOLUTION**
17 **ADOPTING CUSTOMER DELIVERY CHARGES THAT FULLY**
18 **REFLECT THE CUSTOMER-RELATED COSTS IDENTIFIED IN THE**
19 **COST OF SERVICE?**

20 **A.** Yes. Recent changes to § 56-585.3(4) of the Code of Virginia allow a
21 cooperative, by way of an affirmative resolution of its board of directors, to make
22 such revenue-neutral adjustments to its rates as are reasonably calculated to
23 collect, through a fixed monthly charge (rather than volumetric charges associated

1 with energy use), any or all of the fixed costs of owning and operating its electric
2 distribution system. In response, the C-BEC board of directors passed an
3 affirmative resolution expressing its desire to set Customer Delivery Charges for
4 all of its rate schedules at levels that will recover all of the customer-related costs
5 as indicated in its most recent cost of service study. The proposed adjustment to
6 C-BEC's Customer Delivery Charges is revenue-neutral, as a result of customer-
7 related costs being removed from the volumetric charge associated with energy
8 use assessed to each rate class. The changes made to C-BEC's rates based on this
9 resolution are intended to meet the requirements of § 56-585.3(4) regarding the
10 recovery of fixed costs by cooperatives, and will allow C-BEC equitably to
11 provide service to low-usage customers (and other services, such as net metering)
12 without imposing subsidization costs on other member-consumers.

13 **Q. WHAT IS YOUR RECOMMENDARION REGARDING C-BEC'S**
14 **CONSUMER DELIVERY CHARGE?**

15 **A.** After considering all of the factors discussed above, I recommend that the
16 Commission allow a Consumer Delivery Charge of \$31.63. In return for the fixed
17 monthly charge of \$31.63 per customer per month, the customer receives the
18 minimum equipment necessary to access the electric grid and to purchase kWh.

19 **Q. WHAT IS THE IMPACT OF THE PROPOSED RATES ON CUSTOMERS**
20 **TAKING SERVICE UNDER SCHEDULE RS-10-U, RESIDENTIAL**
21 **SERVICE AT VARIOUS USAGE LEVELS?**

22 **A.** The impact of the proposed rates for customers taking service under Schedule RS-
23 10-U, Residential Service, is shown on page 1 of Schedule 6.

1 Q. WHAT IS THE PROPOSED REVENUE INCREASE FOR SCHEDULE CS-
2 10-U, COMMERCIAL AND SMALL POWER SERVICE?

3 A. C-BEC is proposing a revenue increase of \$55,443, or 11.17%, for the Schedule
4 CS-10-U, Commercial and Small Power Service class of customers. The cost of
5 service study indicates that the rate of return for this class is 3.08% and a
6 significant increase was necessary to move the rate of return on this class in the
7 direction of the overall rate of return for the Cooperative. The Cooperative is
8 proposing that the Customer Delivery Charge be increased from \$14.00 per
9 customer per month for single phase service to \$34.95 per customer per month.
10 C-BEC is proposing that the Customer Delivery Charge be increased from \$18.00
11 per customer per month for multi phase service to \$38.95 per customer per month.
12 C-BEC also is proposing to eliminate the declining block rate structure for the
13 Commercial and Small Power Service class and to unbundle the energy charge
14 into a purchased power demand charge of 2.268 cents per kWh, a purchased
15 power energy charge of 3.658 cents per kWh and a distribution demand charge
16 assessed on a kWh basis of 3.689 cents per kWh, for a total energy charge of
17 9.615 cents per kWh. The Wholesale Power Cost Adjustment Charge would
18 initially be reset to zero but would be assessed in addition to this base energy
19 charges as C-BEC's purchased power costs deviated from the purchased power
20 costs included in its base rate. These charges reflect the corresponding costs from
21 the cost of service study as shown on Schedule 7, Attachment B, page 20.

1 **Q. WHAT IS THE IMPACT OF THE PROPOSED RATES ON CUSTOMERS**
2 **TAKING SERVICE UNDER SCHEDULE CS-10-U, COMMERCIAL AND**
3 **SMALL POWER SERVICE AT VARIOUS USAGE LEVELS?**

4 **A.** The impact of the proposed rates for customers taking service under Schedule CS-
5 10-U, Commercial and Small Power Service is shown on pages 2 and 3 of
6 Schedule 6.

7 **Q. WHAT IS THE PROPOSED REVENUE INCREASE FOR SCHEDULE LP-**
8 **10-U, COMMERCIAL AND LARGE POWER SERVICE?**

9 **A.** C-BEC is proposing a revenue increase of \$4,675, or 0.46%, for the Schedule LP-
10 10-U, Commercial and Large Power Service class of customers, as shown on page
11 1 of Schedule 5B. The cost of service study indicates that the rate of return for
12 this class is 38.88%, which is why only a small increase in revenue was assigned
13 to this class. The Cooperative is proposing that the Customer Delivery Charge be
14 increased from \$40.00 per customer per month to \$88.32 per customer per month.
15 C-BEC is also proposing to eliminate the declining block rate structure for
16 Commercial and Large Power Service and to unbundle the energy charge into a
17 purchased power demand charge of \$3.12 per non-coincident peak kW-month, a
18 distribution demand charge of \$7.50 per non-coincident peak kW-month, and a
19 purchased power energy charge of 7.1 cents per kWh. The Wholesale Power Cost
20 Adjustment Charge would initially be reset to zero but would be assessed in
21 addition to this base energy charges as C-BEC's purchased power costs deviated
22 from the purchased power costs included in its base rate. These charges reflect

1 the corresponding costs from the cost of service study as shown on Schedule 7,
2 Attachment B, page 20.

3 **Q. WHAT IS THE IMPACT OF THE PROPOSED RATES ON CUSTOMERS**
4 **TAKING SERVICE UNDER SCHEDULE LP-10-U, COMMERCIAL AND**
5 **LARGE POWER SERVICE, AT VARIOUS USAGE LEVELS?**

6 **A.** The impact of the proposed rates for customers taking service under Schedule LP-
7 10-U, Commercial and Large Power Service, is shown on page 4 of Schedule 6.

8 **Q. WHAT IS THE PROPOSED REVENUE INCREASE FOR SCHEDULE**
9 **OL-10, OUTDOOR LIGHTING SERVICE?**

10 **A.** C-BEC is proposing a revenue increase of \$3,415, or 4.04%, for Schedule OL-10,
11 the Outdoor Lighting class of customers. The cost of service study indicates that
12 the rate of return for this class is 13.37%. Because this is significantly above the
13 rate of return for the total system, relatively little of the rate increase was
14 allocated to this class of customers. The Cooperative is not proposing to increase
15 the charge for a 175 watt mercury vapor light on an existing pole, holding it
16 constant at \$9.85 per month. C-BEC also is not proposing to increase or the
17 charge for a 175 watt mercury vapor light on an additional pole, holding it
18 constant at \$12.10 per month. The apparent increase in revenue collected from
19 this class results from the \$3,379 difference between actual test year revenues and
20 reconstructed revenues as shown on page 5 of Schedule 5B and not as a result of
21 any change in the rates for Outdoor Lighting Service.

22 **Q. DOES C-BEC PROPOSE TO CHANGE ITS TERMS AND CONDITIONS**
23 **FOR PROVIDING ELECTRIC DISTRIBUTION SERVICE?**

1 A. Yes. Some of the changes are to make the Terms and Conditions more readable,
2 some changes are to clarify definitions of terms, some are clarify the Terms and
3 Conditions, and there is a substantive change to the line extension policy. The
4 changes to C-BEC's Terms and Conditions are provided in Schedule 5A. I will
5 explain the change in the line extension policy and the other changes in the
6 Cooperative's Terms and Conditions.

7 **Q. PLEASE EXPLAIN THE CHANGES THAT C-BEC WANTS TO MAKE**
8 **TO ITS LINE EXTENSION POLICY FOR CUSTOMERS TAKING**
9 **SERVICE FOR A PERMANENT RESIDENCE.**

10 A. C-BEC wants to significantly simplify its existing line extension policy and to
11 provide credits for new construction that fairly balance the interests of new and
12 existing customers. The Cooperative is proposing a credit of \$1,631 for line
13 extensions for customers taking service for a permanent residence. This credit
14 was calculated by dividing net utility plant of \$19,182,328 for the Residential
15 Service class of customers from the cost of service, as shown on page 2 of
16 Schedule 7, Attachment B, by the 5,881 customers in the Residential Service class
17 during the test year, resulting in a net plant investment per customer of \$3,262.
18 After deriving this net plant investment per customer, half was allocated as a
19 proper contribution to the backbone system and half was provided as a credit to
20 the customer requesting the line extension. Philosophically, all customers should
21 be contributing to the backbone system. The line extension gets a customer
22 access to the nearest line while the backbone system provides the necessary
23 access the rest of the way to generation sources. The \$1,631 represents an

1 average of what the Cooperative has invested in line extensions to meet the needs
2 of existing customers in the Residential Service class and represents a fair credit
3 against the cost of extending new service to a customer's permanent residence
4 served under that rate class.

5 **Q. WHAT CHANGES DOES C-BEC WANT TO MAKE TO ITS LINE**
6 **EXTENSION POLICY FOR NON-RESIDENTIAL CUSTOMERS?**

7 **A.** For non-residential customers, the Cooperative is proposing a credit against the
8 cost of adding a new customer that is based on a times net revenue approach.
9 Specifically, C-BEC proposes to provide a credit of 2.5 times the estimated
10 distribution delivery revenue, where distribution delivery revenue is defined as
11 gross revenue received from the customer minus the cost of purchased power
12 necessary to serve the customer. There would be a true-up after 30 months based
13 on the actual distribution delivery revenue recovered from the customer during
14 the first 30 months of service. This true-up could result in additional
15 contributions in aid of construction paid by the customer or refunds for
16 contributions in aid of construction already paid by the customer. For
17 subdivisions, the developer would pay for all of the additional costs for the
18 backbone system necessary to serve the subdivision and customers would be
19 responsible for the line extensions pursuant to the line extension policy for
20 serving a permanent residence described above, as they purchased lots and
21 connected to the system.

1 **Q. WHAT OTHER CHANGES IS THE COOPERATIVE MAKING TO ITS**
2 **TERMS AND CONDITIONS OF SERVICE?**

3 A. The definition of "Permanent Residence" has been moved from the section
4 dealing with Extension of Facilities to the Definition section. In addition, the
5 definition of adult is clarified to mean a person 18 years of age or older, and the
6 definition of a Member is clarified to mean the entire family unit. The payment of
7 interest on customer deposits has been changed from annual to monthly payment
8 of interest. The section dealing with interconnection of small generators has been
9 changed to conform to Commission standards. Finally, because of safety
10 concerns, field personnel will no longer accept payment to avoid service
11 disconnection due to late payment. Payments will only be accepted in the
12 Cooperative's office, during normal business hours.

13 **Q. IS C-BEC PROPOSING TO MODIFY ANY OF ITS FEES FOR NON-**
14 **RECURRING CHARGES?**

15 A. Yes. The Cooperative is proposing changes to the fees for non-recurring charges
16 to more accurately reflect the actual cost of providing the associated services.
17 Some of the fees in Schedule F were revised during the 2005 rate case while other
18 charges have not been changed since the rate case in 1993. Significant changes in
19 the cost of providing the associated services have occurred since that time and the
20 Cooperative is proposing to make the necessary revisions to reflect these changes.
21 In addition, C-BEC has implemented an AMI system that has fundamentally
22 changed the way it does business, requiring further changes to the Cooperative's
23 non-recurring charges. The changes in non-recurring charges are shown in

1 Schedule F – Fees, attached as Appendix A to the Terms and Conditions of
2 Service.

3 **Q. DOES C-BEC PLAN TO OFFER TIME OF USE RATES TO ANY OF ITS**
4 **CUSTOMERS?**

5 A. Yes. C-BEC plans to offer optional time of use rates to its Residential Service
6 and Commercial and Small Power Service customers. The time of use rates are
7 optional and customers may, but are not required to, obtain service under these
8 rates if they believe that these time of use rates will provide a benefit for them.
9 The time of use rates are designed to be revenue neutral for each class of
10 customers if the customers in the class made no changes to their electric energy
11 usage patterns. However, if customers move some of their on-peak usage to off-
12 peak periods, Customer's can reduce their energy bills and the Cooperative can
13 reduce its purchased power costs from its suppliers.

14 **Q. PLEASE DESCRIBE THE OPTIONAL TIME OF USE RATE FOR**
15 **RESIDENTIAL SERVICE CUSTOMERS (RSTOU-1-U).**

16 A. The Schedule RSTOU rate would be applicable to any Customer who qualifies for
17 service under the Residential Service Rate including, residential and
18 residential/farm consumers, schools, seasonal, ball fields, churches and
19 community halls. It would consist of a Customer Delivery Charge and time-
20 differentiated energy charges. The Customer Delivery Charge would be \$31.63
21 per customer per month, the on-peak energy charge would be 17 cents per kWh,
22 and the off-peak energy charge would be 7.615 cents per kWh. The Wholesale
23 Power Cost Adjustment Charge would be assessed to both the on-peak and off-

1 peak energy charges. The on-peak period would be 6 AM to 8 AM and 3 PM to 8
2 PM daily. The Off-Peak period would be all other hours.

3 This rate was designed to be revenue neutral compared to both the Residential
4 Service Rate. If all of the Cooperative's Residential Service customers were to
5 sign up for the RSTOU rate, the Cooperative would receive the same amount of
6 revenue, unless the customers were to shift their loads from one period to the
7 other. If customers shifted load from the on-peak period to the off-peak period,
8 the Cooperative's costs would decrease by the same amount as the revenue
9 decrease, thus leaving the Cooperative financially unaffected by this shift.

10 **Q. PLEASE DESCRIBE THE OPTIONAL TIME OF USE RATE FOR**
11 **COMMERCIAL AND SMALL POWER SERVICE CUSTOMERS**
12 **(CSTOU-1-U).**

13 A. The Schedule CSTOU rate would be applicable to any Customer who qualifies for
14 service under the Commercial and Small Power Service Rate including, single-
15 phase and multi-phase commercial consumers with demands of 15 kW or less. It
16 would consist of a Customer Delivery Charge and time-differentiated energy
17 charges. The Customer Delivery Charge for customers taking single phase
18 service would be \$34.95 per customer per month. The Customer Delivery Charge
19 for customers taking multi phase service would be \$38.95 per customer per
20 month. The on-peak energy charge for all customers served under Rate CSTOU
21 would be 14.3 cents per kWh and the off-peak energy charge would be 7.347
22 cents per kWh. The Wholesale Power Cost Adjustment Charge would be
23 assessed to both the on-peak and off-peak energy charges. The on-peak period

1 would be 6 AM to 8 AM and 3 PM to 8 PM daily. The Off-Peak period would be
2 all other hours.

3 This rate was designed to be revenue neutral compared to both the Commercial
4 and Small Power Service Rate. If all of the Cooperative's Commercial and Small
5 Power Service customers were to sign up for the CSTOU rate, the Cooperative
6 would receive the same amount of revenue, unless the customers were to shift
7 their loads from one period to the other. If customers shifted load from the on-
8 peak period to the off-peak period, the Cooperative's costs would decrease by the
9 same amount as the revenue decrease, thus leaving the Cooperative financially
10 unaffected by this shift.

11 **Q. PLEASE DESCRIBE THE OPTIONAL GREEN POWER RIDER THAT C-**
12 **BEC IS PROPOSING.**

13 A. The Green Power Rider is available to any customer taking electric service under
14 any of the Cooperative's rate schedules who wishes to purchase "Green Power"
15 from the Cooperative. Green Power includes energy generated from renewable
16 and/or environmentally friendly sources, including: Wind; Solar Photovoltaic,
17 Biomass Co-firing of Agricultural Crops and All energy crops; Hydro – as
18 certified by the Low Impact Hydro Institute; Incremental Improvements in Large
19 Scale Hydro; Coal Mine Methane; Landfill Gas; Biogas Digesters; and Biomass
20 Co-firing of All Woody Waste including mill residue, but excluding painted or
21 treated lumber. Green Power will be provided by purchasing renewable energy
22 certificates ("RECs") from the sources described above. RECs are tradable units
23 that represent the commodity formed by unbundling the environmental attributes

1 of a unit of renewable or environmentally friendly energy from the underlying
2 electricity. One REC would be equivalent to the environmental attributes of one
3 MWh of electricity from a renewable or environmentally friendly generation
4 source. The rate charged for all Green Power kWh will be \$0.015 per kWh, with
5 a minimum kWh purchase of 100 kWh and additional purchases to be made in
6 100 kWh block increments. The customer will enter into a service agreement
7 with the Cooperative that will specify the amount of Green Power, in kWh blocks,
8 to be purchased monthly. Customers must give the Cooperative thirty days notice
9 prior to cancellation of participation in this rider.

10 **Q. HAVE YOU PREPARED AN EXHIBIT SHOWING C-BEC'S COMPLETE**
11 **TARIFF REFLECTING THE PROPOSED RATES?**

12 **A.** Yes. The Cooperative's new tariffs, along with "redlined" copies showing the
13 changes from the current tariffs, are included in Schedule 5A.

14 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

15 **A.** Yes, it does.

Prior Testimony of Dr. Martin J. Blake

Federal Energy Regulatory Commission

- ER92-533 LG&E's open transmission access and authority to charge market-based rates for its generation.
- ER94-1380 The first comparability tariff approved by the FERC.
- ER97-4345 A market power analysis that was filed in support of OGE Energy Resources, Inc.'s request for the authority to charge market based rates.
- ER98-511 A market power analysis that was filed in support of Oklahoma Gas and Electric Co.'s request for the authority to charge market based rates.
- ER99-51 An affidavit in support of Commonwealth Edison Co.'s request for authority to charge cost based rates to its affiliates.
- ER01-1938 Testimony in support of Southern Indiana Gas and Electric Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
- ER02-708 Testimony in support of Central Illinois Power Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
- NJ03-2 Testimony in support of Southern Illinois Power Company's request for a revision in ancillary service rates
- EL03-53 Testimony regarding the calculation of avoided cost for a qualifying facility interconnecting with a cooperative
- EL02-111 Testimony regarding the process for developing a combined transmission service rate that would apply to the combined Midwest ISO and PJM footprint

Arkansas Public Service Commission

- 96-360-U Direct and rebuttal testimony for Oklahoma Gas and Electric regarding recovery of stranded costs by Entergy Arkansas, Inc.

California Public Utility Commission

- 90-12-018 Direct and rebuttal testimony for Southern California
(phase 5) Edison Company concerning the reasonableness of contracting by Southern California Edison with Integrated Energy Group ("IEG") to provide marketing services to Southern California Edison and the reasonableness of the resulting marketing services performed by IEG.

Colorado

- Error! Reference source not found.** Provide an independent review, assessment and recommendation concerning Public Service Company of Colorado's Application and request for the Commission to approve the Company's 2007 Colorado Resource Plan ("2007 CRP") and to review supporting testimony in this proceeding as it relates to the retirement of Cameo Units 1 and 2 and Arapahoe Units 3 and 4.

Illinois Commerce Commission

- 98-0013 and Testimony regarding non-discrimination with
98-0035 regard to affiliate transactions for electric utilities. I sponsored ComEd's proposed affiliate transactions rules and suggested some basic principles that the Illinois Commerce Commission should follow in developing rules and regulations for ensuring non-discrimination and non-cross subsidization in transactions with affiliated and unaffiliated alternative retail electric suppliers ("ARES").
- 98-0036 Testimony in a rulemaking to develop rules and regulations for assessing and assuring the reliability of the transmission and distribution systems as a part of electric utility restructuring in Illinois.
- 98-0147 and Testimony concerning standards of conduct and
98-0148 rules for functional separation. I sponsored ComEd's proposed standards of conduct and functional separation rules.
- 07-0572 Testimony in a reconciliation proceeding concerning the prudence and recovery of the costs of gas injections and withdrawals from the Hillsboro storage field.

Kentucky Public Service Commission

- 90-158 An LG&E rate case.
- 92-494 An LG&E biennial fuel adjustment clause review.

- 93-150 An application for approval of a DSM cost recovery mechanism and a set of initial programs.
- 94-332 An application for an environmental cost recovery mechanism.
- 92-494-B Testimony regarding the confidentiality of coal bid data.
- 95-455 A biannual review of the environmental cost recovery mechanism.
- 91-423 Participation in the conference with Commission staff and intervenors to review LG&E's first integrated resource plan.
- Other Several fuel adjustment clause proceedings on behalf of LG&E.
- 98-489 Testimony on behalf of Blazer Energy Corp. in an application for an adjustment in their natural gas rates.
- 99-046 Direct and rebuttal testimony regarding Return on equity in support of Delta Natural Gas Company's request for an adjustment in rates
- 04-00067 Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates
- 07- 00089 Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates

Nevada Public Utility Commission

- 01-10001 Direct testimony on behalf of Shareholders Association to support Nevada Power Company's request for return on equity

New Mexico Public Utility Commission

- 2797 Direct and rebuttal testimony in a general rate case for Plains Electric Generation and Transmission Cooperative, Inc.

Virginia State Corporation Commission

- PUE-2008-00076 Direct and Rebuttal testimony regarding rate design for Northern Neck Electric Cooperative

U.S. District Court, District of New Mexico

- CIV-08-00026 Reviewed the Expert Report filed by Gary L. Groninger and provided rebuttal testimony regarding whether a decision that was made by the Arkansas River Power Authority (ARPA) was prudent.

Oklahoma Corporation Commission

- PUD 960000116 Testimony in an Oklahoma Gas and Electric Company rate case, including rebuttal of intervenor and staff proposals to disallow certain marketing, advertising, economic development and research and development expenses.
- PUD 200300226 Testimony in an Oklahoma Gas and Electric Company case regarding the prudence of natural gas transportation and storage contracts

Indiana Utility Regulatory Commission

- 41884 Direct and rebuttal testimony to support a request by eleven gas local distribution companies for switching from a quarterly gas cost adjustment mechanism to a monthly gas cost adjustment mechanism
- 42027 Direct testimony in support of a transfer of functional control of transmission assets from electric utilities in Indiana to the Midwest System Operator, Inc.

Colorado Public Utility Commission

- 02S-594E Direct and surrebuttal testimony regarding pro forma adjustments to the revenue requirement in Aquila Networks-WPC rate case.
- 03S-539E Testimony regarding the use of zero intercept methodology to allocate distribution costs and determine an appropriate customer charge in an Aquila Networks-WPC rate case.
- 07A-447E Testimony regarding Public Service Company of Colorado's Integrated Resource Plan.

Iowa District Court for Hamilton County

- No. LACV025993 Testimony that net metering was not appropriate for making payments to a wind generator. When a utility sells electric energy to a customer, it is charging a retail rate that recovers the cost of distribution, transmission and generation service. When a customer sells electric energy to a utility, it is selling only generation service. The customer cannot sell distribution and transmission service to a utility, as the customer does not own these assets. Net metering is a subsidy to the wind generator that is paid by other customers of the utility and paying the customer for generation service on the basis of a retail rate that includes recovery of distribution and transmission costs is not appropriate.

Among the most important values behind the whole concept of a co-op is a sense of dependability, openness and fairness – everyone paying their fair share, everyone having the real facts and everyone being confident that we have the resources to protect your investment and service your needs for the future. Craig-Botetourt Electric Cooperative strives to bring you reliable electric service at reasonable rates and wants to be as fair as possible to all of its customers with regard to the rates that it charges. Because we needed to know our true costs, Craig-Botetourt began a study to help us determine what it actually costs to serve each customer — whether residential, commercial, industrial or outdoor lighting. While everyone needs a meter, transformer, poles and power lines for electric service, other requirements vary depending on the type of customer.

Like any business, we need to make sure our prices match our costs so our rates are fair, based on facts, and set at a level that will allow us to provide reliable service to everyone. With that in mind, we hired a utility expert to conduct a cost-of-service study. The study took all of Craig-Botetourt’s actual expenses for the year 2008 and allocated them to the various classes of customers based upon such things as usage patterns, equipment necessary to provide service, and types of service. The study then looked at our prices for each of these types of customers and types of services to see if they matched.

In most cases they did not. The differences had to do with rate design — the individual components of your monthly bill that represent things like the cost of facilities that everyone shares, the costs of facilities that serve you directly and the actual cost of the energy you use. Here is what the study showed about each type of service:

| Type of Service | What is it? | New Cost-Based Charges | Current Charge July-December |
|--------------------------|--|--|---|
| Customer Delivery charge | Your share of cost for poles, wires, transformers, service drop and meters that give you access to the electric grid | \$31.63 per residential customer per month | \$14.00 per residential customer per month |
| Energy charge | Cost of buying electricity you use and delivering it to your residence over the transmission system and our distribution network | 10.677¢ per kilowatt-hour plus the wholesale power cost adjustment | 13.014¢ per kilowatt-hour for the first 250 kWh 11.464¢ per kilowatt-hour for the next 500 kWh |

| | | | |
|--|--|--|--|
| | | | 9.164¢ per kilowatt-hour for over 750 kWh |
|--|--|--|--|

Currently, much of the cost of facilities and equipment to provide customer access to the electric grid is recovered through the kilowatt hour charge. The customer delivery charge is a charge for a portion of the cooperative's physical facilities such as poles, wire, transformers, service drops, and meters and recovers the cost of the minimum amount of equipment that is necessary to provide a customer with access to the electric grid. Having a customer delivery charge that is too low means that some customers with very low usage are not paying their fair share of the cost of the cooperative's physical facilities, while customers with large usage are typically paying more than their fair share of these physical facilities.

So, why is the customer delivery charge coming out so high? Based on the cost of service study, our current customer delivery charge does not come close to covering the fixed cost of providing the minimum amount of equipment necessary for a customer to access the electric grid. Everyone shares the costs of our facilities because the system operates as a whole and providing reliable service to everyone is what a cooperative is all about. Additionally as a rural electric cooperative, we cannot spread our fixed costs over as many customers as some of our neighbors. The following chart shows why it costs us more per customer than some utilities nearby using the cost of distribution line as an example – the wires that go down your street and eventually to your home or business:

| Utility | Cost/mile of distribution cable | Customers/mile | Cost/customer |
|--------------------------------------|---------------------------------|----------------|---------------|
| Dominion Virginia Power | \$30,000 | 36 | \$833 |
| Craig-Botetourt Electric Cooperative | \$30,000 | 6 | \$5,000 |

In our more rural area, we simply do not have as many customers who can share the costs of these facilities, but they are still facilities needed to provider everyone with the same quality of service.

Furthermore, we think that the new residential customer delivery charge is in line with the cost of basic services for other utilities in the area. In the counties served by the Cooperative, the charges for basic utility service, with no premium services included, are:

1. Basic telephone service ranges from \$22.99 to \$30.02
2. Basic cable service ranges from \$29.99 to \$59.95
3. Basic satellite dish service ranges from \$14.98 to 29.99
4. Water & Sewer service ranges from \$35.00 to \$70.00
5. Internet service ranges from \$12.95 for dial up to \$49.99 for fiber optic

Why does it matter to you that our rates for facilities and energy match the actual costs? Why is it important to separate them? It is simply an issue of fairness. If the customer delivery charge is too low and energy rates are too high, customers with low usage are really not paying their fair share of the cooperative's fixed costs for the facilities that are needed to provide service to them. At the same time, heavier users are really paying too much of the cooperative's fixed costs because of the large amount of fixed costs included in the energy charge in our current rate. Our Board believed that these charges needed to be changed to a rate design that was fairer to all customers, with all customers paying their fair share of the facilities used to serve them.

As a non-profit cooperative with a commitment to offer the same quality of service and fair rates to everyone, we plan to revise our rate structure to reflect these facts. This will result in increasing the customer delivery charge and the demand charge for customers that pay a demand charge. Customers that were paying less than their fair share of the physical facilities of the cooperative before the rate change was made now pay a charge that matches the costs that they cause the cooperative to incur. Similarly, customers that were paying more than their fair share of the physical facilities of the cooperative before the rate change are now not subsidizing the costs caused by other customers.

No rate change is easy. But this change in rate structure also has the benefit of making your utility costs more predictable. Before the rate change when the energy charge was higher, if the weather became extremely hot or cold, your bill would swing upward pretty sharply. Now, while you may be one of these paying proportionately more each month for your facilities in the customer charge, you will not see as big a swing in your energy charge.

In addition to stabilizing your personal energy costs, this change will also have a benefit to you as a cooperative member. With the rate design that is in effect today that has a high energy rates subsidizing the fixed costs of facilities for other customers, the co-op was in good shape financially when the weather was extremely hot or cold, but mild weather meant we were not recovering our costs for facilities and did not have funds available for improvements. Now Craig-Botetourt can be more assured of what its revenues will be so it can plan improvements for the future – rain or shine, snow or heat.

We plan for these rate changes to go into effect in April, 2010. We value you as a co-operative member and hope this information is helpful to you in understanding what is needed to ensure you have reliable, affordable and fairly priced service.