

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

RE: THE TARIFF SHEETS FILED BY PUBLIC)
SERVICE COMPANY OF COLORADO WITH) DOCKET NO. 07S-521E
ADVICE LETTER NO. 1495 -- ELECTRIC)

**ANSWER TESTIMONY AND EXHIBITS OF DENNIS J. SENGER
ON BEHALF OF THE COLORADO OFFICE OF CONSUMER COUNSEL**

March 24, 2008

TABLE OF CONTENTS

I.	BACKGROUND AND QUALIFICATIONS	1
II.	BACKGROUND OF INTERRUPTIBLE PROGRAMS	5
III.	CONSIDERATION OF ENVIRONMENTAL AND SOCIETAL BENEFITS	7
IV.	CALCULATION OF THE CREDIT	9
A.	Summer Capacity Rating	9
B.	Carrying charge	11
VI.	MARKETING COSTS.....	20
VII.	FINANCIAL INCENTIVE	21
VIII.	RECOMMENDATIONS.....	22

I. BACKGROUND AND QUALIFICATIONS

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

A. My name is Dennis J. Senger. I am a Rate Analyst representing the Office of Consumer Counsel (“OCC”). My business address is 1560 Broadway, Suite 200, Denver, CO 80202.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND YOUR EXPERIENCE IN THE PUBLIC UTILITY FIELD?

A. I have attached Appendix A to my testimony providing a summary of my education and experience.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN PUBLIC UTILITY RATE PROCEEDINGS?

A. Yes, I have submitted testimony in numerous such proceedings before the Minnesota Public Utilities Commission, the New Mexico Public Utilities Commission, the Colorado Springs City Council, and the Colorado Public Utilities Commission (“Commission”). In those proceedings, I have presented written and oral testimony on a variety of rate and regulatory matters related to electricity, natural gas, water, and wastewater service to retail and wholesale customers.

My experience that has most relevance to this docket is as follows:

- 1 • With the Minnesota Department of Public Service I reviewed and
2 prepared recommendations on interruptible rates and marginal/avoided
3 cost calculation,
- 4 • In New Mexico I designed interruptible programs based on avoided
5 costs calculations that comprised more than 10% of the peak load of the
6 utility, and
- 7 • In Colorado Springs I designed an interruptible program similar to the
8 program in place and proposed here by Public Service Company
9 (“PSCo”).

10 **Q. DESCRIBE THE OCC AND ITS INTEREST IN THIS PROCEEDING.**

11 A. The OCC is charged with the responsibility to “represent the public interest and,
12 to the extent consistent therewith, the specific interests of residential consumers,
13 agricultural consumers, and small business consumers.”¹ In this case the OCC’s
14 responsibility is to represent the broad public interest, including environmental
15 and societal considerations, and also to present the concerns and perspective(s) of
16 specific consumers who are “nonparticipating firm customers” in this proceeding.

17 **Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.**

18 A. The OCC is very supportive of demand response programs that provide better
19 incentives for customers to use energy wisely. In my testimony, I have attempted

¹ CRS 40-6.5-104

1 to address three threshold questions:

- 2 1. Is the offering a cost effective program?
- 3 2. Are there negative impacts on nonparticipants and if so how bad are they?
- 4 3. Are there significant externalities to be considered?

5 These questions provide the context in which my conclusions are drawn.

6 I have reviewed the filing and have found that the basic design of this offering is a
7 good one and deserves to be continued. However, I have found that the proposed
8 calculation of the credit includes two technical and methodological errors that,
9 unless corrected, will result in a program that is not cost effective and, as a result,
10 has significant negative impacts on nonparticipants. I have also found a problem
11 with the billing method for interruptible customers with 10-minute notice that also
12 should be corrected to ensure that the program is cost effective and does not harm
13 nonparticipants. Lastly, I do not agree with the proposals to include a financial
14 incentive and incremental marketing costs in the pool of costs to be recovered
15 through an annual rider.

16 **Q. HAVE YOU PREPARED AN EXHIBIT TO PROVIDE A SUMMARY OF**
17 **THE IMPACT OF YOUR PROPOSED CORRECTIONS?**

18 A. Yes, I have. Exhibit____(DJS-1) will serve that purpose. This exhibit provides a
19 comparison of the calculation of the “Foundation Value” in Mr. Taylor’s Exhibit
20 No. AST-1 with the same calculation including the two OCC corrections. You

1 can see that the impact of the OCC corrections is to reduce the Foundation Value
2 from \$7.63/month to \$5.38/month. The Foundation Value is the basis for all of
3 the credit calculations.

4 **Q. HAVE YOU CONSIDERED THAT YOUR RECOMMENDATIONS WILL**
5 **HAVE A NEGATIVE IMPACT ON THE AMOUNT OF**
6 **INTERRUPTIBLE LOAD THAT WILL BE DEVELOPED?**

7 A. Although the Company has stated a concern with the amount of load on this
8 program, they have not presented any evidence that their preference is warranted.²
9 If the credit is lower than what PSCo has proposed, there will likely be fewer
10 consumers who find it beneficial to participate in the program. It is unclear how
11 much of the suggested doubling from current levels³ is due to the proposed price
12 increase and how much is due to the other program improvements. The important
13 policy consideration is what is in the public interest. The OCC believes that the
14 financial interest of consumers is a more important than the meeting of some
15 arbitrary target for an individual program.

16 Electric consumers face a real challenge--paying the bill for what promises to be
17 an increasingly expensive energy future. It is incumbent on the Commission to
18 scrutinize programs to ensure that they are not more expensive than necessary.

² Direct Testimony and Exhibits of Scott B. Brockett, p. 6, Lines 14-19.

³ Direct Testimony and Exhibits of Scott B. Brockett, p. 16, Line 23

1 Absent some showing of substantial environmental or societal benefit, a matter
2 that I will address later in my testimony, the OCC must defend the pocketbooks of
3 the consumers it represents. From all this, a somewhat slower development of
4 interruptible load under this program should not be an overriding concern of the
5 Commission.

6 If what it takes to get the level of demand reduction forecast for this program by
7 PSCo is the large overpayment that will result from the PSCo proposal, I conclude
8 that there are better ways of obtaining the additional capacity. To put this all into
9 perspective, a customer on the option that provides for a one-hour notice with 40
10 annual maximum hours of interruption will receive \$1.46 (or more, depending on
11 load factor)⁴ for each kWh interrupted in the year. I believe there are a number of
12 other programs, including a critical peak pricing program for small commercial
13 and residential customers, that could be successful with a significantly lower
14 critical peak price than \$1.46/kWh.

15 **II. BACKGROUND OF INTERRUPTIBLE PROGRAMS**

16 **Q. PLEASE PROVIDE SOME BACKGROUND OF INTERRUPTIBLE**
17 **PROGRAMS TO HELP THE COMMISSION IN ITS CONSIDERATION.**

18 **A.** Interruptible service offerings have been part of the electric utility landscape for

⁴ Direct Testimony and Exhibits of Scott B. Brockett, Exhibit No. SBB-1. $\$4.87 * 12 / 40 = \1.46 .

1 about as long as there has been an electric utility industry. Interruptible rate
2 offerings were originally developed, at least in part, as a way to increase sales to
3 customers with generation. At their best, interruptible offerings have been a
4 valuable resource that allows the utility to reduce its supply side resource
5 requirement for the benefit of all customers. At their worst, interruptible offerings
6 have been a method of providing a rate discount to price sensitive and/or
7 politically powerful customers, often to the detriment of other customers. The
8 latter cases have generally been marked by few, if any interruptions, and most
9 disturbingly a dramatic decrease in participation at the times of greatest need.

10 Due in part to the long history of interruptible service offerings, utilities are
11 familiar with the service and often make interruptible and direct load control
12 programs the stars of their demand response offerings. While the OCC is not
13 opposed to these programs, an important issue of concern must be the impact of
14 these programs on the nonparticipants, in particular low-income customers. With
15 good program design, nonparticipants will benefit or at least not be financially
16 harmed by the program. Unlike a program that has significant non-pecuniary
17 benefits, such as reduced carbon emissions, there is no real justification for
18 implementing interruptible offerings in a way that have significant impacts on
19 nonparticipants.

**III. CONSIDERATION OF ENVIRONMENTAL AND SOCIETAL
BENEFITS**

**Q. YOU MENTIONED THAT THE LEGISLATIVE CHARGE TO THE OCC
IS TO REPRESENT THE PUBLIC INTEREST INCLUDING
CONSIDERATION OF THE ENVIROMENTAL AND SOCIETAL
ASPECTS OF THE PROGRAM. PLEASE PROVIDE SOME
BACKGROUND ON THESE IMPORTANT TOPICS FOR THE
COMMISSION TO CONSIDER.**

A. A popular conception is that interruptible programs, such as the one in this case, have clear and significant environmental and societal benefits, specifically in the area of reduced carbon emissions and/or displacement of future coal-fired capacity. While well designed interruptible programs will result in efficiency gains and therefore have some environmental and societal benefits, close examination of the programs shows that there will be little if any improvement in the area of reduced carbon emissions or displacement of future coal-fired capacity.

**Q. WHY WILL THE INTERRUPTIBLE PROGRAM HAVE A NEGLIGIBLE
IMPACT ON CARBON EMISSIONS?**

A. By design, the interruptible program is limited to a relatively few of the highest load hours of the year. During these hours, there is little likelihood that coal-fired generation will be on the margin, therefore any reduced customer use in these

1 hours will likely result in reduced natural gas generation, not a reduction in coal-
2 fired generation. Furthermore, with the buy-through provisions of this program,
3 most interruptions will not actually result in a significantly reduced use--most
4 customers will exercise their right to continue purchasing electricity during the
5 interruption, albeit at a slightly higher cost. Lastly, some unknown portion of the
6 interrupted load will simply be shifted to another time and will not result in
7 reduced carbon emissions.

8 **Q. WHY WILL THE INTERRUPTIBLE PROGRAM NOT DISPLACE**
9 **FUTURE COAL-FIRED GENERATION?**

10 A. Again, this is due to the nature of the program; i.e. that it will only be used for a
11 small number of hours during the year. The type of future capacity that it will
12 replace will be a type of peaking capacity and not coal-fired capacity that will
13 only be economical to build for serving load used a substantial number of hours
14 each year.

15 **Q. GIVEN YOUR CONCLUSION THAT THERE ARE NEGLIGIBLE**
16 **ENVIRONMENTAL AND SOCIETAL BENEFITS BEYOND THE**
17 **EFFICIENCY GAINS OF A WELL DESIGNED PROGRAM, WHAT DO**
18 **YOU RECOMMEND TO THE COMMISSION AS A STANDARD FOR**
19 **EVALUATING THIS PROGRAM?**

20 A. In the absence of significant non-pecuniary externalities, the evaluation of what is

1 in the public interest becomes much more straightforward. In such cases, the
2 OCC endorses Mr. Brockett's standard that "[t]he ISOC program should provide
3 financial benefits to nonparticipating firm customers"⁵, at the very least,
4 nonparticipating customers should not be harmed by the program.

5 **IV. CALCULATION OF THE CREDIT**

6 **Q. PLEASE DESCRIBE THE CALCULATION METHOD USED BY MR.**
7 **TAYLOR.**

8 A. Mr. Taylor's Exhibit No. AST-1 presents the steps he used in calculating what he
9 calls the Foundation Value. He commences his calculations with the selection of
10 a representative supply-side resource that would potentially be acquired or
11 developed in the absence of a program such as the interruptible program proposed
12 here. He then includes transmission costs necessary to interconnect the CT to the
13 system. I agree with the Mr. Taylor's calculation to this point.

14 **A. Summer Capacity Rating**

15 **Q. MR. TAYLOR'S NEXT STEP IS TO "NORMALIZE" THE COST TO**
16 **REFLECT THE CAPACITY RATING OF THE CT TO PEAK SUMMER**
17 **CONDITIONS. DO YOU HAVE ANY CONCERNS WITH THE**
18 **ADJUSTMENT?**

⁵ Direct Testimony and Exhibits of Scott B. Brockett, p. 12, Lines 3-4.

1 A. Yes I do. I should also note that this step is a departure from the method
2 previously used by PSCo. While I agree with the general concept that Mr. Taylor
3 is trying to achieve, I do not agree with how he has incorporated it into his
4 calculations. We must remember what we are trying to accomplish with this
5 calculation--establishing the value that PSCo will realize by having an option to
6 interrupt a customer for a specified number of hours in the year. Mr. Taylor
7 justifies his use of summer rating by his statement that these are the conditions
8 "...likely to be prevailing..."⁶ during an interruption. His method is inconsistent
9 with Mr. Brockett's statement that PSCo should "bank some hours as an
10 insurance policy...against potential reliability issues later in the year".⁷ Yet Mr.
11 Taylor's adjustment fails to account for the value that a CT would provide year-
12 round. Put another way, if PSCo purchased a CT, it would have access to that
13 resource year round--during most of that time the summer capacity rating is not
14 reflective of the value of the resource.

15 **Q. HOW DO YOU PROPOSE TO CORRECT FOR THIS OMISSION?**

16 A. I propose a method using the seasonal ratios proposed by Mr. Sheesley.⁸ Mr.
17 Sheesley's proposal is that each of the four summer months will have a weighting
18 of 115%, while each of the other months will have a weighting of 90%. Using

⁶ Direct Testimony and Exhibits of Alan S. Taylor, p. 4 line 15

⁷ Direct Testimony and Exhibits of Scott B. Brockett, p. 14 lines 20-22

⁸ Direct Testimony and Exhibits of Timothy J. Sheesley, p. 7-8

1 these factors, the capacity derating will be to 141.4 MW.⁹

2 **B. Carrying charge**

3 **Q. PLEASE CONTINUE WITH YOUR DESCRIPTION OF MR. TAYLOR’S**
4 **CALCULATION.**

5 A. Next, Mr. Taylor calculates and applies a fixed charge rate to the unit costs he has
6 calculated up to this point. He states that the step is to derive “...the annual
7 levelized cost to the utility’s customers if PSCo were to construct a Frame CT and
8 ratebase its investment.”¹⁰

9 **Q. PLEASE DESCRIBE THE METHOD USED IN THE CALCULATION OF**
10 **THE FIXED CHARGE RATE.**

11 A. I examined the methodology Mr. Taylor used to develop the credit. The method
12 used by Mr. Taylor is relatively straightforward. First, he calculates the revenue
13 requirements that would be incurred over the 30 year life of the CT.

14 **Q. DO YOU HAVE ANY CONCERNS WITH THE CALCULATION OF THE**
15 **REVENUE REQUIREMENT?**

16 A. No, I agree Mr. Taylor’s calculation in this regard.

⁹ $((128.9 \text{ MW} * 4 \text{ mo} * 1.15) + (153.3 \text{ MW} * 8 \text{ mo} * .9)) / 12 = 141.4$

¹⁰ Direct Testimony and Exhibits of Alan. S. Taylor, p. 5 lines 7-8.

1 **Q. PLEASE CONTINUE WITH YOUR DESCRIPTION OF THE**
2 **CALCULATION OF THE FIXED CHARGE RATE.**

3 A. Mr. Taylor then takes the 30 years of revenue requirements arising from the
4 purchase of the CT and determines the present value of those requirements.
5 Next, he calculates the levelized annual amount that, if paid over each of the next
6 30 years, would pay the equivalent of the present value of the requirements.

7 **Q. DO YOU AGREE WITH MR. TAYLOR'S APPROACH OF LEVELIZING**
8 **THE REVENUE REQUIREMENTS IN ORDER TO DEVELOP THE**
9 **INTERRUPTIBLE CREDITS TO BE PAID?**

10 A. No, I do not. I would like to preface this discussion by defining two types of
11 levelization, a nominal levelized carrying charge ("NLCC") and a real levelized
12 carrying charge ("RLCC"). The NLCC, the method used by Mr. Taylor, refers to
13 a method that levelizes the payments in nominal dollars. The method that I will
14 propose, RLCC, is a levelization of payments in real dollars, meaning the
15 payments will increase over time to reflect inflation.

16 **Q. PLEASE EXPLAIN WHY A NLCC RATE SHOULD NOT BE USED IN**
17 **SETTING THE INTERRUPTIBLE CREDIT IN THIS CASE.**

18 A. The critical consideration for the determination of the appropriate carrying
19 charge is that the method is dependent on the structure and term of the
20 "contract." Mr. Taylor's use of a NLCC would be appropriate if the credit would

1 remain unchanged for the balance of the life of the replaced resource, in this case
2 30 years. That assumption is clearly not realistic for this program. Customers'
3 rates are periodically reset, generally about every three years. When that occurs,
4 the interruptible credit will and should be recalculated using the latest cost
5 estimates, including the new inflation adjusted capital costs. As a result the
6 interruptible credits that are being established in this case, will likely not remain
7 unchanged for 30 years, but instead will likely be reset at a higher value
8 approximately every three years.

9 **Q. DO YOU HAVE ANY EVIDENCE THAT THE INTERRUPTIBLE**
10 **CREDIT WILL BE RESET IN THE FUTURE?**

11 A. We do not need to look any farther than this case to see that evidence. The
12 current credit was established in 2005 as a result of Docket No. 04S-164E. In
13 that case, PSCo used the same nominal levelizing technique.¹¹ Here we are,
14 essentially three years later, with a request to substantially increase the credit due
15 in part to reflect a new levelization performed on the increased capital cost of
16 new capacity.

17 **Q. DO YOU HAVE ANY EXAMPLES OF THE USE OF THE RLCC IN**
18 **UTILITY RATEMAKING?**

19 A. Yes, I do. N/E/R/A is an internationally recognized leader in the field of

¹¹Direct Testimony and Exhibits of Alan S. Taylor, p. 5, line 5-6

1 marginal cost pricing. At least as far back as 1977 N/E/R/A recognized that, for
2 setting rates, investment in new plant must be converted into annual costs using a
3 RLCC.¹² I have included as Exhibit____(DJS-2), selected pages from studies
4 N/E/R/A prepared as early as 1977 and as late as 2004, demonstrating
5 N/E/R/A's long-standing use of this practice.

6 **Q. DO YOU HAVE ANY EXAMPLES OF THE ADOPTION OF THE RLCC**
7 **BY ANY UTILITY REGULATORY BODIES?**

8 A. Yes, I do. The most recent example that I am aware of is a California Public
9 Utilities Commission Decision 07-09-040, dated September 20, 2007.¹³ Two
10 findings from that order are particularly instructive:

11 34. Using a levelized nominal dollar value to compute the CT cost
12 would overstate the avoided capacity cost as well as present
13 additional cost and risk for utilities and ratepayers.

14 35. Using an economic carrying charge rate, escalated for inflation
15 over the life of the contract, allows us to provide more flexibility in
16 contract terms, from one year up to ten years with the same CT
17 cost estimate.

18 The California Commission has recognized the same problem that we face here.

19 The rates will not remain in effect for the same term as the life of the
20 representative resource. Their solution, consistent with my proposal, is to base the

21 payments on a RLCC consistent with the length that the payments will be fixed.

¹² N/E/R/A uses the term annual economic charge to refer to what I have called the real levelized carrying charge.

¹³ This decision was the resolution of two rulemaking dockets, 04-04-003 and 04-04-025, that addressed resource planning and avoided cost calculation.

1 **Q. MR. SENGER, HAVE YOU CALCULATED A RLCC CONSISTENT**
2 **WITH THE RELEVANT ASSUMPTIONS MADE BY MR. TAYLOR?**

3 A. Yes I have. I have attached the derivation as Exhibit____(DJS-3).¹⁴ In
4 order to make the RLCC consistent with the three year rate case cycle, I
5 have used the average of the first three years, when the rates would be in
6 effect. This average is a rate of 12.06%.

7 **Q. EARLIER YOU STATED THAT USING A NLCC RESULTS IN A**
8 **SUBSTANTIAL OVERPAYMENT. CAN YOU EXPLAIN WHY THIS**
9 **OVERPAYMENT WOULD OCCUR?**

10 A. The unspoken assumption of Mr. Taylor is that the credits remain the same for
11 the 30 years life of the facility. I have modeled the much more probable scenario
12 that the credits will be reset approximately every 3 years, incorporating then
13 current costs.¹⁵ In this scenario, the present value of the credits that will be paid
14 over the 30 years is \$157 million, \$30 million (24%) more than the present value
15 of the avoided revenue requirements. This demonstrates that use of the NLCC
16 rate will result in payments by ratepayers of substantially higher payments of
17 credits to interruptible customers than if PSCo bought the CT.

18 Another view of this overpayment is provided by the graph that I have included

¹⁴ Please note that the appropriate formula for the RLCC calculation appears in Exhibit____(DJS-2), Page 3 of 7.

¹⁵ See Exhibit____(DJS-4).

1 as Page 2 of Exhibit____(DJS-4). That graph starts with the two lines showing
2 the payment over 30 years for the NLCC--the horizontal dotted line--and the
3 RLCC—the upward sloping solid line. These two lines both have equivalent
4 present values for their cumulative payments--\$127 million. The third line—the
5 increasing steps depicted by the dashed line--represents the PSCo proposal. This
6 payment pattern will result in the payment of \$157 million in present value, an
7 overpayment by nearly 24% over the 30 year program.

8 **Q. DO YOU HAVE ANY OTHER COMMENTS ON MR. TAYLOR'S**
9 **CALCULATION PRESENTED IN EXHIBIT NO. AST-1?**

10 A. Not at this time.

11 **V. 10-MINUTE NOTICE BILLING METHOD**

12 **Q. IN DOCKET NO. 06S-642E, DECISION NO. C07-0559, THE**
13 **COMMISSION ORDERED A WORKSHOP(S) BE HELD TO ADDRESS,**
14 **AMONG OTHER THINGS, AN EXAMINATION OF THE LEVEL OF**
15 **COINCIDENCE BETWEEN ISOC PARTICPANTS AND THE SYSTEM**
16 **PEAK. HAVE YOU ANALYZED THIS ISSUE?**

17 A. Yes I have. Unfortunately, the workshop did not result in any resolutions to the
18 concerns that have been raised. Part of the problem is that the program is still
19 new enough that not enough data exists to fully understand the magnitude of the
20 problem. I have one recommendation that will partially address this issue, but

1 more importantly will provide for a better match of the value paid for value
2 received.

3 **Q. PLEASE CONTINUE.**

4 A. Mr. Brockett described the increased value of the offering to customers receiving
5 10 minutes notice stating that “the difference is that loads that can be curtailed in
6 less than 10 minutes can be treated as operating reserves.”¹⁶ What has not been
7 done, in my opinion, is match the way that operating reserves are measured with
8 the billing method that is used for these interruptible customers.

9 **Q. WHAT ARE OPERATING RESERVES AND HOW ARE THEY**
10 **MEASURED?**

11 A. Operating reserves are divided into two categories, spinning reserves (unloaded
12 generation which is synchronized and ready to serve additional demand) and
13 nonspinning reserves (generation not connected to the system but capable of
14 serving demand within ten minutes, or interruptible load that can be removed
15 from the system within ten minutes). Interruptible load can only be claimed as
16 operating reserves to the extent that it is online and available.

17 **Q. PLEASE DESCRIBE THE CURRENT AND PROPOSED METHOD FOR**
18 **DETERMINING THE KW AMOUNT THAT WILL BE PAID TO**

¹⁶ Direct Testimony of and Exhibits of Scott B. Brockett p. 5 line 5-6.

1 **CUSTOMERS.**

2 A. There are three components used in the determination of the kW amount that is
3 included in the calculation of the monthly credit. Each customer specifies a
4 Contract Firm Demand amount that is not subject to interruption. Next, each
5 customer has a Contract Interruptible Load which is equal to the median of that
6 customer's maximum daily 1-hour integrated demand occurring between noon
7 and 8:00 p.m. Monday through Friday, excluding federal holidays, during the
8 months of June through September, less the Contract Firm Demand. The last
9 component is the Interruptible Demand, which is defined as the maximum 1-hour
10 kW demand between noon and 8:00 p.m. Monday through Friday, excluding
11 federal holidays for the month, less the Contract Firm Demand. The kW amount
12 used in the calculation of the interruptible credit is the lesser of the Contract
13 Interruptible Load or the Interruptible Demand.

14 **Q. DOES THIS METHOD PROVIDE A REASONABLE MEASURE OF THE**
15 **AMOUNT OF OPERATING RESERVES THAT PSCO CAN CLAIM FOR**
16 **THE INTERRUPTIBLE LOAD?**

17 A. No, it does not, in my opinion. I contend that this method will generally deviate
18 (overstate) the amount of operating reserves that PSCo can claim. In some cases
19 this deviation can be quite dramatic. This can be clearly seen by examining
20 Attachment 2 of the Report of the Participants in the ISOC Workshop Held on

1 August 9, 2006 (“Workshop Report”).¹⁷ This data reveals the amount of load that
2 was online just prior to and therefore available for interruption at the top 40 hours
3 of PSCo’s system peak. It also presents the amount of interruptible capacity that
4 was being paid for and that should have been available for interruption in those
5 times.

6 Exhibit____(DJS-6) is a graph of the data presented in Attachment 2 of the
7 Workshop Report. In this graph, the data shown is the percentage of the load that
8 was being paid for that was online and available at the time of PSCo’s highest
9 loads. The highest amount available was 79% of the amount paid for, and there
10 was one hour in which only 16% of the purchased capacity was available for
11 interruption. The average for the 40 hours was 58%. Just as it is appropriate to
12 derate the CT capacity to reflect actual operating conditions, the same must be
13 done to the interruptible loads

14 **Q. DO YOU HAVE A RECOMMENDATION TO IMPROVE THIS**
15 **MISMATCH?**

16 **A.** Yes I do. Keep in mind what we are trying to accomplish—compensate the
17 interruptible customers for the value that PSCo is able to receive by virtue of
18 having load that qualifies as nonspinning operating reserves. My
19 recommendation is to substitute the following as the definition of Interruptible

¹⁷ See Exhibit____(DJS-5)

1 Demand:

2 The Interruptible Demand, determined by meter measurement,
3 shall be the ~~maximum~~**average** of the 1-hour integrated kilowatt
4 demands used during the month, less the Contract Firm Demand, if
5 any, but not less than zero. Interruptible Demand is measured
6 between the hours of 12:00 noon to 8:00 p.m. Monday through
7 Friday, excluding federal holidays **and days an interruption is**
8 **called.**

9 **VI. MARKETING COSTS**

10 **Q. PSCO PROPOSES TO RECOVER ANY INCREMENTAL MARKETING**
11 **COSTS ATTRIBUTABLE TO THE ISOC PROGRAM THROUGH THE**
12 **DSMCA RIDER. DO YOU AGREE WITH THIS PROPOSAL?**

13 A. No, I do not. First, PSCo has not provided any justification why the Commission
14 should deviate from its historical practice of not allowing marketing costs in rates
15 at all, let alone why it should recover incremental costs in a rider. The only
16 mention of its request is Mr. Brockett's notification that it will request such
17 recovery in an advice letter.¹⁸ Mr. Brockett goes on to agree to a cap on the
18 allowable marketing costs of 5% of the total credits.¹⁹

19 Since PSCo has not explained why the proposal should be granted, it is difficult to
20 argue against it. What I can say is that it is one more cost item that PSCo wants to
21 recover without a full accounting of revenue needs that would result from a rate

¹⁸ Direct Testimony and Exhibits of Scott B. Brockett, p 17, Lines 15-19.

¹⁹ Direct Testimony and Exhibits of Scott B. Brockett, p 18, Lines 5-12.

1 case. The OCC is opposed to such single-issue ratemaking as being generally
2 unfair to consumers. This will allow PSCo to recover additional costs of a narrow
3 category without any determination that other costs are also changing.

4 **VII. FINANCIAL INCENTIVE**

5 **Q. HAVE YOU CONSIDERED THE REQUEST BY PSCO TO RECEIVE A**
6 **FINANCIAL INCENTIVE IN THE FORM OF A PERCENTAGE OF THE**
7 **INTERRUPTIBLE CREDITS PAID TO CUSTOMERS?**

8 A. Yes, I have. It is my recommendation that PSCo not receive a financial incentive
9 for interruptible credits. It is my understanding that PSCo is seeking this
10 incentive primarily as a concern that the lost revenue/margins that it would
11 experience makes it reluctant to support the otherwise desirable programs. In this
12 case, all of the credit payments made to interruptible customers are collected
13 through the DSMCA rider. As a result, any energy sales reductions will be
14 extremely small, as discussed above, any lost margins will be negligible.

15 Actually, I have a more fundamental concern about a financial incentive,
16 particularly as proposed by PSCo in this case. The Commission should be
17 concerned about creating a situation that would give PSCo a financial reward
18 based on the amount of interruptible credits paid. Under this type of incentive
19 structure, PSCo will benefit by increasing the credit. As the voice of the
20 nonparticipating customer in this matter, the OCC does not want an incentive

1 structure that puts PSCo clearly on the side of the participants.

2 **Q. DO YOU HAVE A PROPOSED IMPROVEMENT TO THE INCENTIVE**
3 **STRUCTURE, IN THE EVENT THE COMMISSION DECIDES THAT AN**
4 **INCENTIVE IS APPROPRIATE?**

5 A. Yes, I do. I recommend an incentive structure that encourages the effective
6 management of the program. Such an incentive would produce efficiency gains
7 that would be of benefit to all customers. An example of such a structure would
8 be to pay an incentive to PSCo for effectively managing the hours of interruption.
9 For example, the incentive structure could be that no incentive would be paid if
10 the number of hours of interruption was less than or equal to 85% of the number
11 of hours available in the year. For each percentage above 85%, PSCo would
12 receive a bonus of 1% of ISOC credits, with the maximum bonus being 10%.

13 **VIII. RECOMMENDATIONS**

14 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE?**

15 A. 1. I recommend that the rated capacity of the representative CT be based
16 upon a weighted average of summer and winter capacity ratings.

17 2. I recommend that the credit be calculated using a real levelized carrying
18 charge reflecting that the credit will be periodically reestablished.

19 3. I recommend that the interruptible demand amount for the 10-minute

1 notice customer be changed to reflect the way that operating reserves are
2 calculated.

3 **4.** I recommend that incremental marketing cost not be included in those
4 costs recovered in the DSMCA.

5 **5.** I recommend that a financial incentive not be paid to PSCo.

6 **Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?**

7 **A.** Yes, it does.

APPENDIX A: STATEMENT OF QUALIFICATIONS

Educational background and Public Utility experience of Dennis J. Senger

I have a B.S. in economics and political science from Northern State University. I graduated with an M.S. in economics from South Dakota State University.

My professional experience in public utilities began in 1980, when I was employed as a Rate Analyst for the Minnesota Department of Public Service (“MDPS”), representing the interests of customers and the public in utility matters before the Minnesota Public Utilities Commission (“MPUC”). While there I worked on and testified before the MPUC on various electric and natural gas rate and regulatory matters. In addition, my duties included testifying before the Minnesota Legislature on energy matters, specifically on small power producers and co-generators, and serving on the National Association of Regulatory Utility Commissioners Staff Subcommittee on Electricity.

In 1985, I left the MDPS and was employed as the Supervisor of Rates and Regulatory Affairs by Plains Electric Generation and Transmission Cooperative (“Plains Electric”). Plains Electric was a wholesale provider of electricity to thirteen rural electric distribution cooperatives in New Mexico and Arizona. Plains Electric merged with Tri-State Electric Generation & Transmission Association, Inc. in 2000. At Plains Electric, I was responsible for all regulatory filings and testified before the New Mexico Public Utilities Commission (“NMPUC”) on a variety of electric rate and regulatory matters.

I left Plains Electric in 1991 to accept a position with Colorado Springs Utilities, as the Manager of Pricing. Colorado Springs Utilities is a municipal utility that provides electric, natural gas, water and wastewater services to the Colorado Springs community and surrounding areas. Under Colorado law, with certain exceptions, the regulation of rates is vested in the governing body of the municipal utility. In the role of Manager of Pricing, I was responsible for the preparation and defense of all rate filings before the Colorado Springs City Council. In September 2003, I was named the Manager of Forecasting and Risk Management. In that role, I was responsible for the load and revenue forecasts for all utility services as well as the supervision of the risk analysis and reporting to the Colorado Springs Utilities' Risk Management Committee.

I left Colorado Springs Utilities and began working at the OCC in November, 2006. The OCC has been established to represent the public interest and the specific interests of residential, agricultural, and small business consumers in rate proceedings before the Colorado Public Utilities Commission ("Commission").

Comparison of Foundation Value Calculation Taylor vs OCC


	AST-1 as filed	OCC Proposed
EIA estimate (\$M, '05\$)	67.2	67.2
Escalated to 2007 @ 2.37% (\$M, '07\$)	70.4	70.4
Transmission (\$M, '07\$)	4.5	4.5
Total (\$M, '07\$) (line 2 + line 3)	74.9	74.9
Normalized (\$/kW) Note 1	581.2	529.9
Fixed Charge Rate Note 2	14.89%	12.06%
Annual (\$/kW-yr) (line 5 * line 6)	86.55	63.91
Monthly (\$/kW-yr) (line 7 / 12)	7.21	5.33
Energy Benefit (\$/kW-mo)	0.30	0.30
Net cost (line 8 + line 9)	6.91	5.03
Adj reactive power	0.25	0.25
Adj AGC	0.25	0.25
Net cost (line10 + line 11 + line 12)	6.41	4.53
Transmission loss	2.56%	2.56%
Net cost (line 13 * (line 14 + 1))	6.58	4.64
Target Reserve	16%	16%
Net cost (line 15 * (line 16 + 1))	7.63	5.38

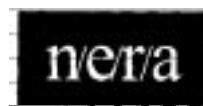
Note 1: Taylor based on 128.9 MW Summer capacity, OCC based on 141.4 weighted average of year-round capacity.

Note 2: Taylor based on Nominal Levelized carrying charge, OCC based on Real Levelized carrying charge.



Commission for Energy Regulation

 Coimisiún um Rialáil Fuinnimh



Consulting Economists

Marginal Cost of Electricity Service Study

CER/04/240
July 1st 2004

VII. COMPUTATION OF ECONOMIC CARRYING CHARGES

To be useful in ratemaking and other marginal cost applications, the marginal investment in new plant must be converted into annual costs using an economic carrying charge (ECC). These annual charges reflect the revenue requirement associated with incremental plant: return to stockholders and bondholders, depreciation, and income taxes.

For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. In such a stream, the first year's charge represents the cost in today's euros of having the plant or equipment for a year. It also represents the rental rate for such an investment in a competitive market.

ECCs were developed from CER estimates of cost of capital components, and our review of tax and accounting regulations. In the cost of equity calculation we used a new risk-free rate based on the CER's computation of BGE's cost of capital,³¹ and made a slight adjustment for the different capital structures in BGE and ESB.³² The economic carrying charges reflect a cost of a cost of equity leveraged to 50-50 debt-equity of 6.5 percent, and 3.9 percent for debt. Although the capital costs are the same for all types of plant, the carrying charges can vary because of differences such as service lives, and depreciation rules. In the carrying charge computation there is provision for a term to incorporate the cost of having to replace assets that fail before their average service life, and delay replacement of assets that last longer. We did not have the information necessary to include this "dispersed retirements" component in this study.

³¹ Commission's Proposals on Transmission Use of System Revenue Requirement and Tariff Structure. October 2003-September 2007; page 11.

³² For all of the ESB businesses, the allowed revenues determination foresees financing of incremental investment through 50% sales of common stock and 50% debt over the study period. BGE's equity cost assumed a structure of 50% equity and 55% debt.

Schedule 45. Economic Carrying Charge for Transmission and Distribution

	Transmission and Other Distribution	Distribution Meters LVFR	Distribution Meters LVMD
	(1)	(2)	(3)
(1) Present Value of Revenue Requirements Related to Incremental 1,000 Euro Investment	1,509.53	1,335.35	1,182.54
(2) Present Value Cost of Replacing Dispersed Retirements Related to Incremental 1,000 Euro Investment	0.00	0.00	0.00
(3) Total Present Value Cost Related to Incremental 1,000 Euro Investment (1)+(2)	1,509.53	1,335.35	1,182.54
(4) First-Year Annual Economic Charge Related to Incremental 1,000Euro Investment ^{^1}	87.45	94.33	113.59
(5) First-Year Annual Economic Charge Related to Incremental Investment [(4)/1,000]	8.74%	9.43%	11.36%

^{^1} The appropriate charge is the first-year charge which rises annually at the rate of inflation net of technological progress. The first-year charge is calculated using the following formula:

$$AC_{t=T} = K(R+J)(1+J)^{T-1} \left(\frac{1}{(1+R)^N} \right)$$

where:

AC_{t=T} = Annual Charge in Year T
T = Year Index
K = Total PV of Revenue Requirement for Original Investment [line (3)]
R = Discount Rate (After-tax incremental cost of capital)
J = Inflation Rate Net of Technical Progress
N = Book Life

HOW TO QUANTIFY **MARGINAL** COSTS: TOPIC 4
RESULTS FOR
VIRGINIA ELECTRIC AND POWER COMPANY
FOR **THE** VIRGINIA **JURISDICTIONAL** SERVICE

Prepared by
National Economic Research Associates, Inc.

Prepared for
ELECTRIC UTILITY RATE DESIGN STUDY:
A nationwide effort by the Electric Power Research
Institute, the Edison Electric Institute, the American
Public ~~Power~~ Association, and the National Rural
Electric Cooperative Association for the
National Association of Regulatory Utility Commissioners

June 6, 1977

VIRGINIA ELECTRIC AND POWER COMPANY
 DERIVATION OF ANNUAL ECONOMIC CHARGE
 RELATED TO CAPITAL INVESTMENT

An annual economic charge related to the marginal investment has been computed for each function. (See Topic 4, Section VIII, for a detailed explanation of the methodology employed here.) This annual charge reflects **Vepco's** overall marginal cost of capital and the life and dispersion pattern for each function. The accounting methods used in these computations are those currently used by Vepco for the Virginia jurisdictional service in compliance with the directives of the Virginia State Corporation Commission. These factors are summarized on Table E of this schedule. Where an **investment** in a particular function physically deteriorates over time (based on its survivor curve), the annual charge also includes a provision for the replacement cost of retirements. Schedule 8, Tables B, C and D show a set of simulated revenue requirements related to an incremental investment by Vepco in the production, transmission and distribution functions.

On Schedule 8, Table A, the present value of revenue requirements is added to the present value of the replacement of retirements to obtain the total present value of costs arising from the investment.

For use in a marginal cost study, **we** feel that the appropriate stream of annual charges is the stream which rises at the rate of inflation net of technical progress and yields

the total present value of all costs (as shown on Table A) over the selected payback period of the investment. The tax life of the investment has been chosen as the payback period in order to best approximate the businessman's situation in the competitive marketplace where risk is a factor he must consider. In such a stream, the first year's charge will represent the cost in present-day dollars of having the machine for a year. The formula used to calculate this stream and the resulting annual economic charge is shown on Schedule 8, Table A. An integral part of this calculation is the estimation of the long-term rate of inflation net of technical progress. While it is never easy to peg an exact rate of future inflation or technical progress, we feel, based on prevailing economic conditions and the consensus of informed views, that the inflation rate net of technical progress should be stated somewhere between zero and 5 percent. In this study, we have used a rate of 3 percent.

VIRGINIA ELECTRIC AND POWER COMPANY
DERIVATION OF ANNUAL ECONOMIC CHARGE
RELATED TO CAPITAL INVESTMENT

	<u>Combustion Turbine (1)</u>	<u>Transmission (2)</u>	<u>Distribution (3)</u>
(1) Present Value of Revenue Requirements Related to Incremental \$1,000 Investment	\$1,345.90 ¹	\$1,433.26 ²	\$1,400.10 ³
(2) Present Value Cost of Replacing Retirements Related to Incremental \$1,000 Investment ⁴	0.00	68.79	168.36
(3) Total Present Value Cost Related to Incremental \$1,000 Investment (1)+(2)	\$1,345.90	\$1,502.05	\$1,568.46
(4) Annual Charge Expressed in Constant Dollars Related to Incremental \$1,000 Investment ⁵	\$163.98	\$155.97	\$162.86
(5) Annual Economic Charge Related to Incremental Investment (4)÷\$1,000	16.40%	15.60%	16.29%

¹ schedule 8, Table B, page 2

² schedule 8, Table C, page 2

³ schedule 8, Table D, page 2

⁴ Retirements based upon the dispersion pattern for each function are replaced in inflated dollars and discounted back to the time of the original investment. The formula for the present value of the replacement in any year is

$$R_t \times (1 + j)^t \div (1 + r)^t$$

where:

R_t = Value of Retirement in Year t

j = Inflation Rate Net of Technical Progress (3%)

t = Year

r = Discount Rate (Overall Marginal Cost of Capital) (11.99%)

⁵ Annual charge expressed in constant dollars is calculated using the following formula. The appropriate charge is the first year's charge which rises annually at the rate of inflation net of technical progress.

$$AC_t = K (r - j) (1 + j)^{t-1} \left[\frac{1}{1 - \left(\frac{1+j}{1+r} \right)^n} \right]$$

where:

AC_t = Annual Charge in Year t

t = Year

K = Total Present Value Cost of Original Investment

r = Discount Rate (Overall Marginal Cost of Capital) (11.99%)

j = Inflation Rate Net of Technical Progress (3%)

n = Tax Life of Investment

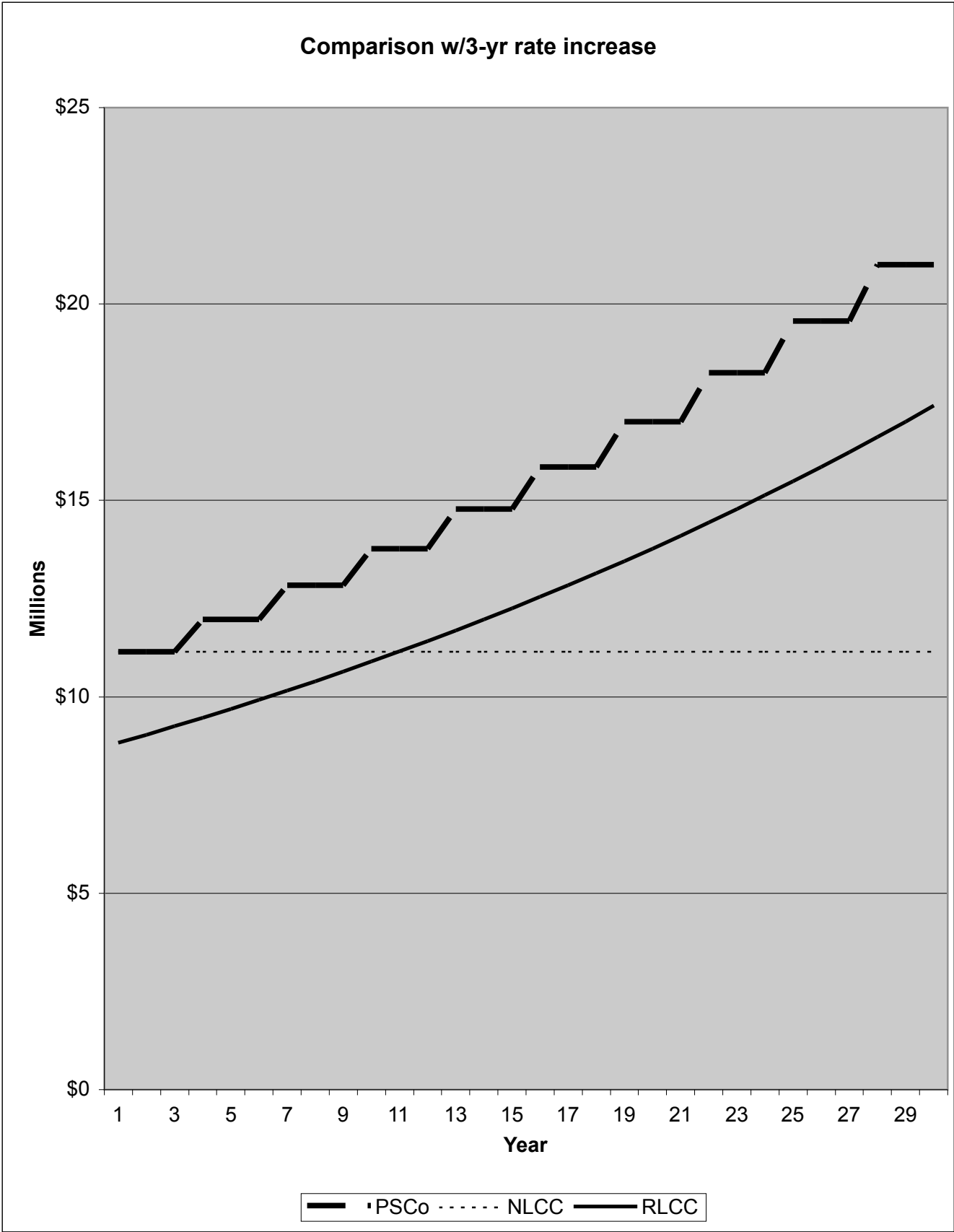
Derivation of Real Levelized Carrying Charge

1	Capital Cost (AST-1 Line 4) (\$M)	74.9
2	NLCC (AST-1 Line 6)	14.89%
3	Annual Revenue Req. (\$M) (Line 1 * Line 2)	11.2
4	PV of 30 years of Revenue Req. (\$M) (Note 1)	126.97
6	3-year average Real Levelized (\$M)	9.04
9	RLCC (Line 6 divided by Line 1)	12.06%

Note 1: PV of 30 years of \$11.2 M @ 7.88% discount rate

Comparison of NLCC with RLCC w/3 Year Adjustment

Year	NLCC w/no adjustments	NLCC w/3 year adjustment	RLCC w/3 year adjustment
1	11.2	11.2	9.0
2	11.2	11.2	9.0
3	11.2	11.2	9.0
4	11.2	12.0	9.7
5	11.2	12.0	9.7
6	11.2	12.0	9.7
7	11.2	12.8	10.4
8	11.2	12.8	10.4
9	11.2	12.8	10.4
10	11.2	13.8	11.2
11	11.2	13.8	11.2
12	11.2	13.8	11.2
13	11.2	14.8	12.0
14	11.2	14.8	12.0
15	11.2	14.8	12.0
16	11.2	15.9	12.8
17	11.2	15.9	12.8
18	11.2	15.9	12.8
19	11.2	17.0	13.8
20	11.2	17.0	13.8
21	11.2	17.0	13.8
22	11.2	18.2	14.8
23	11.2	18.2	14.8
24	11.2	18.2	14.8
25	11.2	19.6	15.9
26	11.2	19.6	15.9
27	11.2	19.6	15.9
28	11.2	21.0	17.0
29	11.2	21.0	17.0
30	11.2	21.0	17.0
PV	\$126.99	\$156.90	\$127.10



INTERRUPTIBLE SERVICE OPTION CREDIT WORKSHOP

DOCKET NO. 06S-642E

REPORT OF THE PARTICIPANTS IN THE ISOC
WORKSHOP HELD ON AUGUST 9, 2006

October 30, 2007

OVERVIEW

Docket No. 06S-642E was opened so that the Commission could consider Public Service Company of Colorado's (public Service's) request for recovery of the payments made to customers that participated in its Interruptible Service Option Credits (ISOC) Program. The recovery period in the docket ran from June 2005 through November 2005; the initial year in which the ISOC Program was implemented.

As part of Decision No. C07-0559, the Commission ordered workshop(s) be held for the purpose of discussing the usefulness of Public Service's cost benefit analysis for the ISOC Program as well as the methodology used to prepare that analysis, and for integrating issues that may be resolved during the course of the workshop(s). Public Service, Staff and other stakeholders were ordered to address, at a minimum, the following issues.

- 1) Examine the level of coincidence between each of the ISOC Program participants' 15-minute integrated kW demand and system peak.
- 2) Evaluate the advisability and implications of applying accrual accounting to the cost recovery.
- 3) Evaluate the usefulness and purpose of preparing a cost-benefit analysis relating to the ISOC Program and the methodology to be used in preparing such an analysis.
- 4) Analyze methods for optimizing the use of ISOC hours including, but not limited to: (a) an analysis of the results of the application of actual data from the last two years of operation of the ISOC Program; and (b) an analysis of how to eliminate blocks of less than four hours.
- 5) Examine and evaluate the economic interruptions that have been called over the last two years of the ISOC Program's operation and how Energy Markets forecasting can be utilized in this process.

The workshop participants were also required to address the reasoning behind the current ISOC requirement that each interruption be at least four hours.

A single workshop was held on August 8, 2007 with representatives from Staff, Public Service, the Office of Consumer Council and Rocky Mountain Steel Mill in attendance. During the workshop Public Service stated that it considered the ISOC Program to be a key component in its effort to grow demand side management. However, in order to grow the program, Public Service explained that it is currently looking at structural changes to the program that may provide greater appeal to prospective customers. Public Service is currently looking at structural changes in the program that may provide greater appeal customers. Some of the ideas under consideration are as follows.

- Reduction of the required minimum load
- Reduction of the minimum duration for an interruption
- Provisions for aggregation of load

- Revisiting the calculation of avoided cost and contract interruptible load
- The use of a negotiated avoided cost rate
- The establishment of financial incentives for Public Service
- Removal of the eligibility requirement that necessitates being a Public Service customer during the prior year's summer season

Staff agrees with Public Service that the ISOC Program has significant growth potential and supports Public Service in exploring changes that could be used to enhance the marketability of the program and to promote participation.

However, issues surrounding both the calculation of the credits and the determination of benefits remain unresolved. While the program holds considerable promise for reaching a viable, cost effective and clean energy solution to meet Colorado's growing resource need, the benefits attributed to the ISOC program need to be realistically calculated to facilitate a comparison with alternate demand side management scenarios. The report presents for further discussion the issues outlined by the Commission in Decision No. C07-0559 presents the parties' plan for going forward.

WORKSHOP ISSUES

The examination of the level of coincidence between each of the ISOC Program participants' 15-minute integrated kW demand and system peak.

Public Service prepared a table to address the issue of coincidence between each of the ISOC Program participant's 15-minute integrated demand and it's system peak. The table was presented at the workshop and is Attachment 1 to this report.

The Commission's order called for an examination of the coincidence between each ISOC Program participant's demand and Public Service's system peak demand. Public Service interpreted this directive to mean that the participants' coincident peak would be examined during Public Service's peak period¹. Therefore, the first column in Public Service's table titled *Max monthly non coincident demand* illustrates the cumulative effect of each participant's maximum peak demand during the month in question. In this instance, there is no coincidence between ISOC participants nor is there coincidence with Public Service's system. The second column titled *Max monthly coincident demand* depicts the highest participant demand on a coincident basis but does not reflect the day or the hour in which Public Service experienced its system peak.

The next two columns depict the billing credits and show whether ISOC Program participants received their full credit for contract interruptible load or whether a participant's monthly peak demand fell below the contract interruptible load and therefore the participant received a reduced ISOC credit.²

¹ Public Service uses the entire peak period for evaluation, a period from 1200 to 2000 when the system peak demand could be expected to occur, versus actual historical data depicting peak demand.

² The tariff bases a participant's Monthly Credit on the lesser of Contract Interruptible Load or the actual Interruptible Demand during the billing month.

The columns titled *Max peak period demand peak day* and *Max coincident peak period demand day* depict the participants' load during the peak period on the day Public Service experienced its monthly system peak. However, although the participants demand reflects the day on which the maximum system demand occurs, it does not reflect the actual hour(s) when the demand on Public Service's system was highest.

Staff took an alternate approach to address the Commission's directive. This analysis is presented in Attachment 2. Based on Public Service's assessment that the lion's share of the value received from the ISOC program comes from avoiding the acquisition of additional resources for serving peak load, Staff looked at Public Service's system during the time when demand on the system was highest. Because of the popularity of the ISOC option which calls for 40-hours of interruption, Staff used a forty hour period over which to assess the coincidence between ISOC load and Public Service's native load obligation.

For the forty hours in question for 2006, 9 hours occurred in the month of June, 27 hours occurred in the month of July, and 4 hours occurred in the month of August. Because Public Service called capacity interruptions during 4 of the top forty hours and economic interruptions during 19 of the top forty hours, the initial half hour segment directly prior to an interruption were used as a proxy for ISOC load during the interruption. Had an interruption not occurred, actual loads could have been higher or lower than the proxies

Data highlighted in blue in Attachment 2 represent the hours in which Public Service called an economic interruption. Data highlighted in yellow represent the hours in which Public Service called an economic interruption. Attachment 2 thus illustrates the power available from ISOC participants for reducing demand on Public Service's system and ranges from 16 percent of the ISOC credit to 75 percent of the ISOC credit. It should be noted that the 16 percent figure represents a day when CF&I was not operating and therefore Public Service's largest customer was not available to reduce load.

Evaluate the advisability and implications of applying accrual accounting to the cost recovery.

During the workshop Public Service agreed to use accrual accounting for cost recovery. In the future, the recovery period will run from January through December of each year.

Evaluate the usefulness and purpose of preparing a cost-benefit analysis relating to the ISOC Program and the methodology to be used in preparing such an analysis.

The parties present at the workshop agreed that a benefit exists from preparing an annual cost benefit of the ISOC Program. However, establishing a method for evaluating the ISOC Program presented the group with a considerable challenge. Notwithstanding the challenge, a definitive evaluation is important not only for establishing a cost effective pricing structure but also for the acquisition of generating resources. Currently the ISOC Program is relatively small, but as the program grows, it will become increasingly more important to correctly determine the amount of demand reduction that should be

attributed to the ISOC participants. The ISOC Program effects Public Service's acquisition of resources and the reliability of its system. Thus the parties must aim to provide the greatest precision possible in the identification of available demand reduction on Public Service's system.

A benefit stemming from the ISOC Program that has been largely overlooked historically is the environmental and societal impacts resulting from demand side management. The ISOC Program provides a viable alternative to resource acquisition and should be acknowledged for the complete array of benefits inherent in reducing demand on Public Service's system. Limiting the evaluation too narrowly may create undo pressure to demonstrate a positive benefit solely from the standpoint of avoided equipment costs. Creating the proper incentives and relying on a comprehensive evaluation of benefits are both for assessing how Public Service should best to meet its native load obligation by choosing cost effective alternatives, including the ISOC Program.

The workshop produced no agreement on a method for evaluating the ISOC Program. It was agreed upon that this issue would be better left to an upcoming docket to be file at the end of October 2007 revisiting the ISOC program and outlining Public Service's plans to expand the program.

Analyze methods for optimizing the use of ISOC hours including, but not limited to: (a) an analysis of the results of the application of actual data from the last two years of operation of the ISOC Program; and (b) an analysis of how to eliminate blocks of less than four hours.

Several ideas were discussed during the workshop including Public Service's right to use the remaining balance of interruptible hours in one final interruption should the balance be less than four hours. In addition, Public Service brought up the question of whether it was better to use all of the remaining interruptible hours or whether it might be better to reduce the credit paid to ISOC customers. This issue is expected to be fleshed out in greater detail in Public Service's filing of proposed changes to the ISOC program expected on October 31, 2006.

Examine and evaluate the economic interruptions that have been called over the last two years of the ISOC Program's operation and how Energy Markets forecasting can be utilized in this process.

Public Service provided a comparison of actual to potential interruptible hours for 2005, 2006 and 2007 (through July). This comparison is included as Attachment 1.

Public Service stated that Energy Markets considers a variety of factors when evaluating whether to call economic interruptions. These factors include projected weather trends, unit maintenance schedules, the availability and cost of energy purchases in the market, and other market conditions affecting the projected near-term and long-term prices of energy. Energy Markets also explicitly includes start-up costs when estimating the avoided costs that could be realized through economic interruptions.

Any decision as to whether to call an economic interruption is largely a matter of judgment; given the uncertainty of future market conditions, it is impossible to conclude with certainty that an economic interruption called on any given day will be more valuable than an interruption called later in the year. The Company will continue to assess carefully the need for economic interruptions with the goal of maximizing program benefits to all customers.

Reasons for the Four-Hour Minimum

Public Service explained that the four-hour minimum was included in the tariff in response to customer concerns about being interrupted many times for short periods. The Company plans to revisit this issue in its upcoming ISOC filing.

WORKSHOP CONCESUS

The parties attending the workshop indicated strong support for continuing the ISOC Program. Public Service reiterated its desire to expand the program as part of its continued commitment to demand side management. Although there are outstanding issues related to the pricing of the program and the method used for the cost benefit analysis, all parties are optimistic that these issues can be resolved.

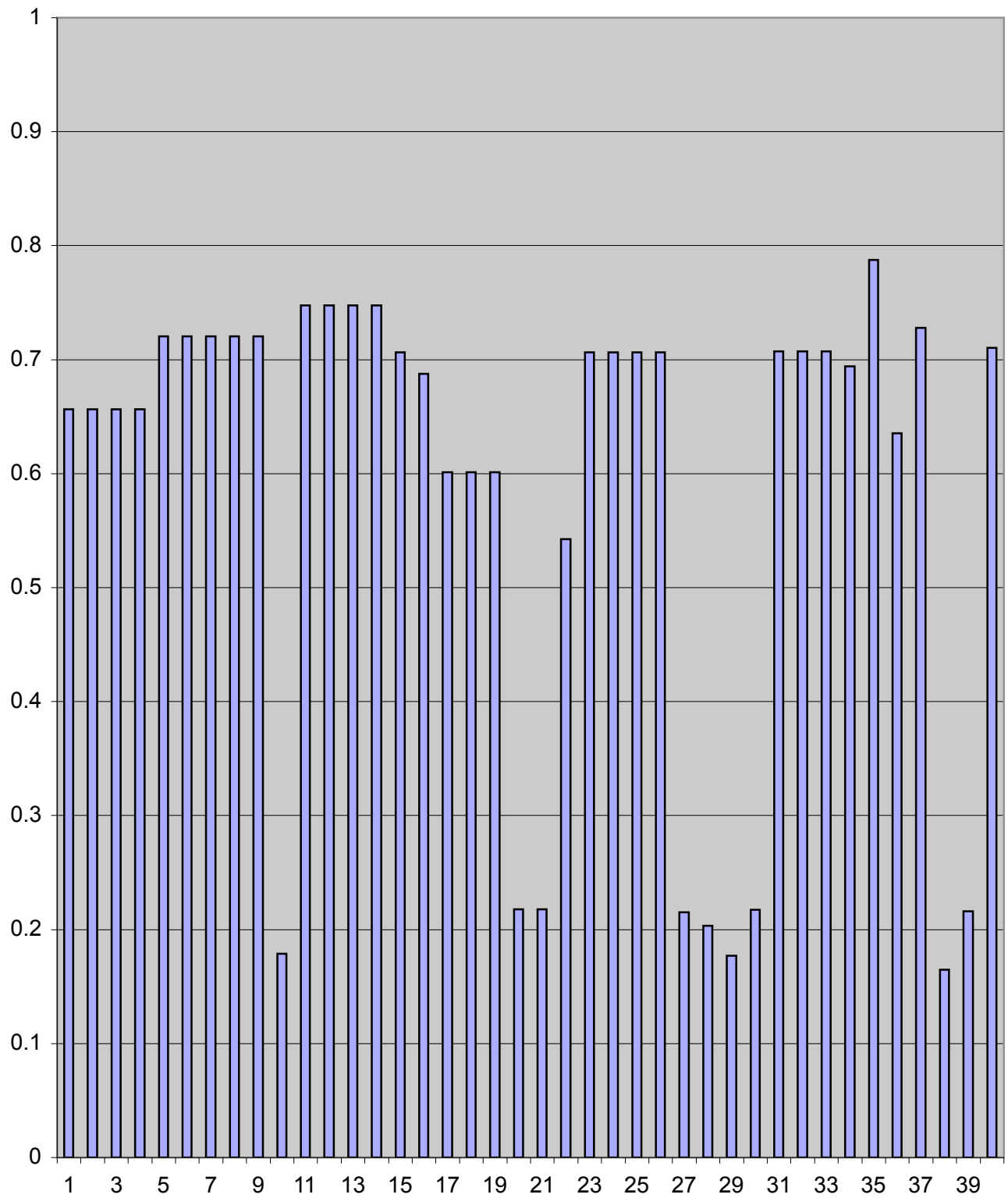
Public Service plans to file an application with proposed changes to the ISOC program for Commission consideration on October 31, 2007. The application will provide a forum for resolving the issues presented herein, and will present an opportunity for reaching a wider audience than the parties attending the workshop. In addition Public Service's upcoming application will afford the Commission a fresh opportunity to weigh in on the extent to which the ISOC Program and other demand side management will help Public Service meet its future resource needs in the larger context of its 2007 Electric Resource Plan.

ISOC Program Participant's 15-minute integrated kW demands on monthly summer peak day

Month	Max monthly non coincident demand	Max monthly coincident demand	Contract Interruptible Load	Monthly credit value kW	Max peak period demand peak day	Max coincident peak period demand peak day	ISOC Status peak period peak day	Peak Day
Jun-05	128,726	117,748	123,884	123,032	120,405	109,258	Partial 2-6 p.m.	20-Jun
Jul-05	128,928	121,918	123,884	121,922	78,300	71,394	None	21-Jul
Aug-05	93,685	80,697	123,884	84,537	79,844	73,163	None	2-Aug
Sep-05	33,490	27,127	123,884	27,554	29,070	24,877	None	7-Sep
Jun-06	128,879	118,927	125,009	123,022	115,111	108,719	Interrupt 2-6 p.m.	14-Jun
Jul-06	128,431	119,129	125,009	120,998	116,873	114,518	Complete 3-7 p.m.	19-Jul
Aug-06	130,447	121,270	125,009	123,590	116,678	108,530	Partial 11 a.m. -7 p.m. Complete 2-6 p.m.	23-Aug
Sep-06	129,579	115,080	125,009	121,326	112,458	108,323	None	6-Sep
Jun-07	131,897	118,337	119,376	119,330	115,635	106,376	Partial 2-6 p.m.	25-Jun
Jul-07	130,673	121,342	119,376	119,291	125,675	113,305	Partial 1-8 p.m.	24-Jul

Attachment 2									
Available ISOC Capacity During Top 40 Hours of PSCO's System Peak									
Date	System Load kW		ISOC Monthly Credit kW		ISOC kW Available for Interruption				
6/13/06 15:00	6,329,744		123,022		80,779			66%	
6/13/06 16:00	6,390,847		123,022		80,779			66%	
6/13/06 17:00	6,418,834		123,022		80,779			66%	
6/13/06 18:00	6,341,160		123,022		80,779			66%	
6/14/06 14:00	6,304,095		123,022		88,614			72%	
6/14/06 15:00	6,371,950		123,022		88,614			72%	
6/14/06 16:00	6,549,778		123,022		88,614			72%	
6/14/06 17:00	6,566,287		123,022		88,614			72%	
6/14/06 18:00	6,498,437		123,022		88,614			72%	
7/13/06 17:00	6,283,588		120,998		21,621			18%	
7/14/06 15:00	6,295,493		120,998		90,432			75%	
7/14/06 16:00	6,357,004		120,998		90,432			75%	
7/14/06 17:00	6,428,110		120,998		90,432			75%	
7/14/06 18:00	6,366,627		120,998		90,432			75%	
7/16/06 17:00	6,285,949		120,998		85,469			71%	
7/16/06 18:00	6,316,904		120,998		83,205			69%	
7/17/06 15:00	6,345,378		120,998		72,752			60%	
7/17/06 16:00	6,388,447		120,998		72,752			60%	
7/17/06 17:00	6,324,562		120,998		72,752			60%	
7/18/06 14:00	6,388,158		120,998		26,361			22%	
7/18/06 15:00	6,364,424		120,998		26,361			22%	
7/19/06 13:00	6,323,272		120,998		65,616			54%	
7/19/06 14:00	6,558,631		120,998		85,496			71%	
7/19/06 15:00	6,618,065		120,998		85,496			71%	
7/19/06 16:00	6,611,533		120,998		85,496			71%	
7/19/06 17:00	6,490,366		120,998		85,496			71%	
7/24/06 14:00	6,348,305		120,998		26,020			22%	
7/24/06 15:00	6,447,128		120,998		24,609			20%	
7/24/06 16:00	6,476,161		120,998		21,414			18%	
7/24/06 17:00	6,378,669		120,998		26,286			22%	
7/28/06 15:00	6,348,759		120,998		85,595			71%	
7/28/06 16:00	6,385,811		120,998		85,595			71%	
7/28/06 17:00	6,402,965		120,998		85,595			71%	
7/31/06 15:00	6,378,643		120,998		83,992			69%	
7/31/06 16:00	6,429,022		120,998		95,276			79%	
7/31/06 17:00	6,302,751		120,998		76,894			64%	
8/8/06 17:00	6,321,087		123,590		89,932			73%	
8/9/06 17:00	6,309,189		123,590		20,368			16%	
8/10/06 16:00	6,276,213		123,590		26,690			22%	
8/23/06 17:00	6,332,458		123,590		87,805			71%	

Available for Interruption During Peak




BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

IN THE MATTER OF ADVICE NO 1495 - PUBLIC)
SERVICE COMPANY OF COLORADO) DOCKET NO. 07S-521E
REVISION TO THE INTERRUPTIBLE SERVICE)
OPTION CREDIT (ISOC) TARIFF – ELECTRIC.)

AFFIDAVIT OF DENNIS J. SENGER


COMES NOW, Dennis J. Senger, of proper age and duly sworn, and states that the foregoing Answer Testimony and Exhibits were prepared by him or under his supervision and control, that they are true and correct to the best of his knowledge and belief, and would be the same if given orally under oath.


Name

STATE OF COLORADO)
CITY AND COUNTY)ss.
OF DENVER)

SUBSCRIBED AND SWORN to before me this 24th day of March, 2008. Witness my hand and official seal.

My Commission expires: 4/14/2011


Notary Public