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

*** * * * ***

RE: IN THE MATTER OF ADVICE	**)**	
LETTER NO. 1712-ELECTRIC FILED BY	**)**	
PUBLIC SERVICE COMPANY OF	**)**	
COLORADO TO REPLACE COLORADO	**)**	**PROCEEDING NO. 16AL-________E**
PUC NO. 7-ELECTRIC TARIFF WITH	**)**	
COLORADO PUC NO. 8-ELECTRIC	**)**	
TARIFF	**)**	

<u>DIRECT TESTIMONY AND ATTACHMENTS OF DONALD E. GARRETSON</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

January 25, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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SUMMARY OF THE DIRECT TESTIMONY OF DONALD E. GARRETSON

Mr. Donald E. Garretson is a Pricing Consultant for Xcel Energy Services, Inc. (“Xcel Energy”). His duties include the development of tariffs to implement the rates, rate structures, terms and conditions for various product offerings, and the analysis of various associated regulatory and business considerations for Public Service Company of Colorado ("Public Service" or "Company"), one of four utility operating company subsidiaries of Xcel Energy.

In his Direct Testimony, Mr. Garretson presents the results of four analyses. The first is an analysis for the years 2010 through 2013 of how customers’ summer usage was impacted by the Inverted Block Rates (“IBR”) that were introduced in 2010 pursuant to Docket No. 09AL-299E (“2009 Electric Phase II Rate Case”) for residential customers taking service under Residential General Service (“Schedule R”).

The second is an analysis for the years 2013 and 2014 of the revenue impact on Public Service from the Time of Use (“TOU”) rates that were approved in the 2009

Electric Phase II Rate Case and introduced in 2010 for large commercial and industrial customers.

The third analysis identifies the impact on 2013 customer billing determinants and revenues of applying the Distribution Demand Ratchet, which was previously approved for Secondary General Service (“Schedule SG”) and Primary General Service (“Schedule PG”) customers.

The fourth analysis explains how the Company developed and used a Bill Frequency Distribution Study to determine the monthly usage intervals used to determine the proposed Grid Use Charges for Schedule R and Commercial Service (“Schedule C”) customers.

The first analysis generally validated the IBR elasticity predictions in the 2009 Electric Phase II Rate Case. The estimates of the actual elasticity impacts ranged from -2.18 percent in 2010 to -4.49 percent in 2013. In the 2009 Electric Phase II the Company predicted an elasticity impact of -3.65 percent.

The second analysis showed that in 2013 and 2014 Public Service lost almost $5 million in revenue - relative to the revenue that would have been generated from the TOU pilot customers had they been served under the standard tariffs.

The third analysis showed that the Distribution Demand Ratchet increased the 2013 billing demands of Schedule SG and Schedule PG customers by 2.2 percent and 2.8 percent, respectively. These additional billing demands increased the Company’s revenues by about $4.2 million.

The fourth analysis was used to identify the appropriate usage intervals and levels for purposes of applying the proposed Grid Use Charges to Schedules R and C. The results were as follows:

Residential (Rate Schedule R)					
Monthly Usage Bands (kWh)	0 to 200	201 to 500	501 to 1000	1001 to 1400	> 1400
Fixed Monthly D Charge	**$2.62**	**$7.76**	**$14.56**	**$25.69**	**$44.79**
Small Commercial (Rate Schedule C)					
Monthly Usage Bands (kWh)	0 to 500	501 to 1000	1001 to 1700	1701 to 3000	> 3000
Fixed Monthly D Charge	**$4.30**	**$13.96**	**$25.22**	**$43.65**	**$92.07**

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
2009 Electric Phase II Rate Case	Docket No. 09AL-299E
Schedule C	Commercial / Small Commercial Service
Schedule C&I	Commercial & Industrial Service
CCOSS	Class Cost of Service Study
CIM	Colorado Public Utilities Commissioner Information Meeting
Commission	Colorado Public Utilities Commission
Company	Public Service Company of Colorado
CP	Coincident Peak
E-Factor	The difference in test period and actual period percent change in price
FARR	Financial Accounting Revenue Report
IBR	Inverted Block Rates
kW	Kilowatt
kWh	Kilowatt Hour
MW	Megawatts
NCP	Non-coincident Peak
Normalization	The evaluation of a single change between two data sets by holding constant all other changes (or variables). In economics called “ceteris paribus” (Latin for “other things being equal”)
Schedule PG	Primary General Service

Acronym/Defined Term	**Meaning**
Schedule PTOU	Primary Time of Use Service
Public Service	Public Service Company of Colorado
R	Residential General Service
RESA	Renewable Energy Standard Adjustment
Self-Selection	When customers choose an alternative tariff because the rate structure reduces the their bills without their changing their level or pattern of usage
Schedule SG	Secondary General Service
Schedule SPVTOU	Secondary Photovoltaic Time of Use Service
Schedule STOU	Secondary Time of Use Service
Straight Reprice	The calculation of the change in revenues associated with a change in price without considering the price elasticity impacts on the level of demand (sales) caused by the price change
TG	Transmission General
TOU	Time of Use
TTOU	Transmission Time of Use
UPC	Use Per Customer
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald Everett Garretson. My business address is 1800 Larimer Street, Denver, Colorado, 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as a Pricing Consultant. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As a Pricing Consultant, I am responsible for the preparation of economic and financial studies to support the development and design of retail electric and gas rates and rate structures. My duties include the development of the costs on which the Company's rates and rate structures are based, the terms and conditions for these product offerings, and evaluations of other regulatory and business considerations. A description of my qualifications, duties and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. In my testimony I present the results of four analyses that I conducted for this proceeding.

The first is an analysis for the years 2010 through 2013 of how customers' summer usage was impacted by the Inverted Block Rates ("IBR") that were introduced in 2010 for those residential customers served under the Residential General Service schedule ("Schedule R"). The Colorado Public Utilities Commission ("Commission") approved these IBR rates in the Company's most recent Electric Phase II proceeding, Docket No. 09AL-299E ("2009 Electric Phase II Rate Case"). In this analysis I demonstrate that the actual elasticity impacts ranged from -2.18 percent in 2010 to -4.49 percent in 2013. In the 2009 Electric Phase II Rate Case the Company predicted an elasticity impact of -3.65 percent.

The second is an analysis for the years 2013 and 2014 of the revenue impact on Public Service from the Time of Use ("TOU") rates that were approved in the 2009 Electric Phase II Rate Case and introduced in 2010 for customers served under the Secondary General Service ("Schedule SG"), Primary General Service ("Schedule PG"), and Transmission General Service ("Schedule TG") schedules. Two TOU offerings were introduced for SG customers: a Secondary Time-of-Use Service ("Schedule STOU") for SG customers that have not deployed photovoltaic panels behind the meter under the Company's Solar Rewards® program; and a Secondary Photovoltaic Time-of-Use Service ("Schedule SPVTOU") for SG customers that have deployed photovoltaic solar panels behind the meter under the Company's Solar Rewards® program. A Primary Time-of-Use Service ("Schedule PTOU") and a Transmission Time-of-Use Service ("Schedule TTOU") were introduced for Schedule PG and TG customers, respectively. My analysis indicates that Public Service lost about $5 million in revenue in 2013 and 2014 - relative to the revenues that would have been generated from these same TOU pilot customers had they been served under the standard tariffs.

The third analysis identifies the 2013 impacts of applying the Distribution Demand Ratchet that the Commission approved in the 2009 Electric Phase II Rate Case on customers' demand billing determinants and bills. This ratchet is applicable to customers on Schedules SG and PG and several related schedules. I conclude from this analysis that the Distribution Demand Ratchet increased the 2013 billing demands of Schedule SG and Schedule PG customers by 2.2 percent and 2.8 percent, respectively. These additional billing demands increased the Company's revenues by about $4.2 million.

The fourth analysis explains how the Company reasonably generated and applied a Bill Frequency Distribution Study to develop our proposed Grid Usage Charges for Schedule R and Commercial Service ("Schedule C") customers.

Q. HOW HAVE YOU ORGANIZED YOUR DIRECT TESTIMONY TO EXPLAIN THE FOUR ANALYSES DESCRIBED ABOVE?

A. In the following four sections of my Direct Testimony, I will explain how I constructed each analysis, comment on my findings, and discuss how each analysis supports the Company's proposals in this Phase II proceeding. The four sections are labeled as follows:

- II. IBR IMPACT ANALYSIS
- III. THE REVENUE IMPACT OF TIME OF USE ("TOU") RATES
- IV. THE DISTRIBUTION DEMAND RATCHET IMPACT ON DISTRIBUTION DEMAND DETERMINANTS
- V. AN EXPLANATION OF HOW BILL FREQUENCY DISTRIBUTION STUDIES WERE USED TO DETERMINE THE PROPOSED CHANGE TO DISTRIBUTION CHARGES FOR THE R AND C RATE SCHEDULES.

II. IBR IMPACT ANALYSIS

Q. WHY ARE YOU PRESENTING AN IBR ANALYSIS IN THIS PROCEEDING?

A. Public Service is presenting the IBR analysis in response to Commission Decision No. C10-0490 at ¶ 97, in the 2009 Electric Phase II Rate Case[1]. In that decision, the Commission ordered Public Service to review the impacts of the IBR in order to determine customers' actual reactions, and to compare these estimated reactions with the Company's estimated reaction in the 2009 Electric Phase II Rate Case.

Q. WHAT IS THE PURPOSE OF THE IBR?

A. The IBR is designed to send better "price signals." In this context the term "price signal" refers to the indication that customers receive through their electricity rates or bills of the "sacrifice" they must make when purchasing electricity in terms of foregoing the purchase of other goods or services. Of course, any price by definition will send some signal to customers. The utility industry's attempts to send better or enhanced price signals is good economic practice, as determined in multiple decisions before regulatory bodies across the country over several decades, and as reflected in the rate-design principles espoused by generally recognized experts such James C. Bonbright.

Q. PLEASE DESCRIBE THE IBR APPROVED FOR SCHEDULE R?

A. In the Company's 2009 Electric Phase II Rate Case it was determined that the Schedule R IBR should consist of two base Energy Charges assessed during the

[1] Docket No. 09AL-299E, the tariff sheets filed by Public Service Company with Advice Letter No. 1535 – Electric.

four summer months of June through September. The first of these base Energy Charges is known as the Tier 1 Energy Charge and applies to all monthly usage up to 500 kilowatt hour ("kWh") during these summer months. The second of these base Energy Charges is known as the Tier 2 Energy Charge and applies to all monthly usage above 500 kWh during these same summer months. The Tier 1 Energy Charge is also applied to all usage during the eight non-summer months (October through May).

It is helpful to identify two aspects of the IBR price signals: (1) the Tier 2 rate is higher than the average rates previously experienced by the customer; and (2) the Tier 1 rate is lower than that average rates previously experienced. In economic terms, the average non-tiered rate is called the P1 rate and the new tiered rates are called P2 rates. The customer's anticipated demand response to these rate changes would be to reduce their usage priced at the higher Tier 2 rate and increase their usage priced at the lower Tier 1 rate.

Q. PLEASE EXPLAIN HOW THE COMPANY PREDICTED THE CUSTOMER REACTION OR RESPONSE TO THE IBR RATES PROPOSED IN THE 2009 PHASE II.

A. In economic terms, customer response is measured by what is called "price elasticity." Price elasticity is the "percentage reaction" to a percentage change in price. When this percentage reaction is multiplied by the percentage change in price, the result is the percentage change in usage. The IBR tariff introduced two price changes, as discussed above. Thus, to predict the customers' response, or change in usage, the Company first needed to predict the price elasticity value, or percentage reaction by customers to the lower Tier 1 (P2) rate and to the higher Tier 2 (P2) rate. We then applied those predicted reactions to the percentage price difference between each of the tiered P2 rates and the previous average rate (P1).

Q. PLEASE EXPLAIN HOW THESE PRICE ELASTICITY VALUES WERE DETERMINED.

A. Public Service hired The Brattle Group to predict the price elasticities. The Brattle Group predicted price elasticity factors of -0.26 for Tier 2 and -0.13 for Tier 1. The Brattle Group model is included in my workpapers and shows how the estimates of -0.26 and -0.13 were applied in the predictions.

Q. HOW WERE THE PERCENTAGE CHANGES IN PRICE DETERMINED?

A. The Company used an average P1 price of $0.0972 per kilowatt-hour ("kWh"), a Tier 2 (P2) price of $0.134 per kWh, and a Tier 1 (P2) price of $0.092 per kWh. The Tier 2 rate was 37.7 percent higher than the average non-tiered rate, and the Tier 1 rate was 5.46 percent lower than the average non-tiered rate.

Q. PLEASE SUMMARIZE THE RESULTS PREDICTED IN THE 2009 ELECTRIC PHASE II RATE CASE.

A. In the 2009 Electric Phase II Rate Case, the Company predicted an annual decrease in energy consumption of 3.65 percent. This estimate was derived by multiplying the price elasticity estimates provided by The Brattle Group for each of the tiers times the percentage change in price that the associated tier represented relative to the average rate. Table DEG-1 below shows the underlying calculations:

Table DEG-1

Annual Results					
Tier	**Price Elasticity-Price Reaction (E)**	**Delta P (% Change in Price)**	**Q1 (Current kWh Usage before Elasticity Impact)**	**Delta Q = E x Delta P x Q1 (kWh)**	**Delta Q /Q1**
Tier 1	-0.13	-5.46%	1,848,514,191	13,121,617	0.71%
Tier 2	-0.26	37.77%	1,307,874,103	-128,421,323	-9.82%
Totals		**Total Q1**	**3,156,388,294**	**-115,299,705**	**-3.65%**

The fourth column in Table DEG-1 shows the usage for the test year used in the 2009 Electric Phase II Rate Case before the impact of elasticity (Q1). In the first row, Table DEG-1 shows that the Q1 value for Tier 1 usage in the summer was 1,848,514,191 kWh. The Tier 1 elasticity of -0.13 was multiplied by the Tier 1 percentage price change of -5.46 percent to yield a 0.71 percent increase in Tier 1 usage, or an increase of 13,121,617 kWh.

In the same manner, the second row of Table DEG-1 shows that the Tier 2 elasticity estimate of -0.26 was multiplied by the Tier 2 percentage change in price of 37.77 percent to yield a 9.82 percent decrease in summer Tier 2 usage. When applied to the Tier 2 Q1 of 1,307,874,103 kWh, the 9.82 percent decrease yielded a reduction in Tier 2 usage of 128,421,323 kWh, as shown in the fifth column of the table. The third row simply sums the changes in usage and divides by the sum of the Q1 values to identify the net change in usage that occurred from the combination of the price elasticity and associated price change for each tier.

Q. WHAT WAS YOUR METHODOLOGY FOR DETERMINING CUSTOMERS' ACTUAL REACTION TO THE IBR?

A. The most direct way to calculate changes to customers' energy consumption in response to IBR rates is to estimate changes in use per customer ("UPC"). For example, in the 2009 Electric Phase II Rate Case, the Company identified an average UPC for June 2010 of 600 kWh before the impact of IBR, but predicted that the IBR would reduce this UPC by 2.6 percent, or to 584 kWh. Therefore, actual UPC results were normalized to the test year to estimate customers' actual reaction.

Q. WHAT DO YOU MEAN BY "NORMALIZED"?

A. In order to compare actual results to those predicted in the test period, any conditions affecting UPC (other than IBR) that changed between the test year and subsequent years must be identified and "stripped out" when estimating the impacts of IBR on UPC during these subsequent years.

Q. HAS THE COMPANY PREVIOUSLY PROVIDED THE COMMISSION WITH INFORMATION ON ACTUAL CUSTOMER RESPONSE TO THE IBR STRUCTURE VERSUS THE PREDICTIONS IN THE 2009 ELECTRIC PHASE II RATE CASE?

A. Yes. A preliminary review of actual customer reaction for the years 2010 through 2012 was provided to the Commission at a January 22, 2013, Commissioner's

Information Meeting ("CIM"). During this CIM, the Company provided estimated reductions in residential energy use of 1.89 percent in 2010, 4.35 percent in 2011 and 3.99 percent in 2012.

In the 2009 Electric Phase II Rate Case, the Company also estimated the impact of the change in usage induced by the IBR on system peak demand. Specifically, the Company estimated a reduction to system peak demand of 51 megawatts ("MW"). Using the same methodology employed in the 2009 Electric Phase II Rate Case, the Company estimates actual reductions to system peak demand of 25 MW in 2010, 60 MW in 2011 and 53 MW in 2012.

Q. DID THE COMPANY SUBSEQUENTLY UPDATE THESE PRELIMINARY RESULTS PROVIDED IN THE CIM?

A. Yes. The Company has updated the analysis provided during the CIM in two respects. First, pursuant to a Commission recommendation at the CIM, the Company added the year 2013 to its analysis. Second, in the process of analyzing 2013 impacts, the Company identified ways to improve our normalization methodology. This updated normalization methodology was also applied to the analysis for 2010 through 2012, which resulted in more refined estimated impacts for these years.

Q. WHY WAS THE ANALYSIS NOT CONTINUED BEYOND 2013?

A. As we go further out in years, it becomes increasingly difficult to make the normalization adjustments between the test year and the actual year. As more time passes, and given the residual approach that this analysis entails, more items that affect usage can occur independent of the elasticity effect. These items would need to be stripped out. Therefore, it becomes increasingly difficult to ensure that all of these other effects on usage are properly considered. In addition, changes in billing accounting procedures over the years - as the Company looks to improve its billing processes - can affect the actual usage data derived from the Company's records. This information must be adjusted to ensure that the data is derived on the same basis as the usage data in the test period.

Had the results of the analysis for the first four years of implementation yielded results that were significantly different than predicted, I would have attempted to conduct an analysis of additional years. However, since the results were close to the predictions and our demand forecasting methodology now includes an elasticity variable based on these results, there seemed to be no added value to pursuing the analysis further.

Q. WHAT IMPROVEMENTS WERE MADE TO THE NORMALIZATION METHODOLOGY?

A. The improvements made to the normalization methodology are summarized in Table DEG-2, below.

Table DEG-2

<table>
<tr><th colspan="3">ITEMS NORMALIZED TO TEST YEAR
[See Attachments DEG-2 & DEG-3 for Formula Samples]</th><th>New Formula?</th><th>Updated Formula?</th></tr>
<tr><td colspan="2">E Factor</td><td>% Difference in Test Period versus Actual Year % of Price Change</td><td>YES</td><td>N/A</td></tr>
<tr><td colspan="2">Normalization of Weather</td><td>Actual UPC adjusted for Weather [Base Year Data was also Weather Normalized]</td><td colspan="2">NO</td></tr>
<tr><td colspan="2">For May Usage Rated Tier Two in a Summer Month</td><td>{[Tier 1 Rev. minus (Tier 2 Rate times Tier 2 Usage)] divided by: minus (Tier 2 Rate minus Tier 1 Rate)}</td><td colspan="2">NO</td></tr>
<tr><td colspan="2">Bill Days Differences</td><td>The % Difference in Avg. Billing Days per Cycle times the Adjustment for the Number of Billing Cycles in the Month</td><td colspan="2">NO</td></tr>
<tr><td colspan="2">Billing Cycles Differences</td><td>FARR UPC minus: {{FARR total usage /(divided by): {[% difference in Number of Test Year Cycles and Actual Year Cycles] times FARR total Customers}}</td><td>NO</td><td>YES</td></tr>
<tr><td rowspan="3">Economic Forecast</td><td>Base Versus Current Year</td><td>Test Year Economic Forecast for UPC minus Actual Year Economic Forecast for UPC</td><td colspan="2">NO</td></tr>
<tr><td>DSM - Actual vs. Forecast</td><td>Test Year Economic Forecast for DSM minus Actual Year Economic Forecast for DSM divided by Total Customers</td><td colspan="2">NO</td></tr>
<tr><td>Adjustment for Solar Rewards</td><td>Added Incremental Impact of Solar Rewards® Deployments</td><td colspan="2">NO</td></tr>
<tr><td colspan="3">Current Period Adjusted to Test Period Weather Normalized</td><td>YES</td><td>N/A</td></tr>
</table>

Table DEG-2 above shows that two new formulas were introduced, and one formula was revised, for a total of three improvements. The additional formulas were the: (1) E Factor, and (2) Current Period Adjusted to Test Period Data Weather Normalized.

The first new formula, the "E Factor," normalizes the actual period percentage price change to the assumed percentage price change in the test period. The actual P1 and P2 prices in each year will differ from the prices during the test period used in the 2009 Electric Phase II Rate Case.[2] Thus, the predicted percentage change in usage will vary even if the same elasticity value is applied since the percentage change in price will be different. The results were normalized for this difference.

The second new formula normalizes test period usage for weather. In the preliminary results, only the actual years were normalized.

The formula was also modified for Billing Cycle normalization. The number of billing cycles billed in any given month can vary from year to year. This causes a change in the UPC from the UPC reflected in the Financial Accounting Revenue Report ("FARR").

Q. WHERE THERE OTHER CONDITIONS FOR WHICH YOU NORMALIZED?

A. Yes. In addition to the improvements mentioned in the previous response, actual results were also normalized for six other conditions. As the preceding table shows, the same normalization approach was used to derive the preliminary and final results.

First, the actual usage in each year was normalized for differences in weather. This is different than the improvement mentioned above, as it was discovered that the test period also needed to be weather normalized.

Second, in the 2009 Electric Phase II Rate Case, all test-year usage during the summer months was assumed to be billed under the summer tiered rate

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[2] As discussed previously, the P1 average price used in the 2009 Electric Phase II Rate Case was $0.0972 per kWh, and the P2 prices were $0.134 per kWh (Tier 2) and $0.092 per kWh (Tier 1). Consequently, the Tier 2 price was 37.7 percent higher than the average P1 rate, and the Tier 1 price was 5.46 percent lower than the average P1 rate.

structure, and thus subject to both the Tier 1 and Tier 2 elasticity impacts. But the FARR report from which this data was gathered captures the amount of usage *billed* in the summer months, regardless of whether this usage was subject to the tiered rate structure or the flat rate structure applied to usage in non-summer months. For example, if a customer's billing cycle falls on the 15th of the month, their June bill will include a month of usage *billed* in June, but only half of that usage will be subject to the summer tiered rates. Specifically, the usage in that bill from May 16th through May 31st will be billed at the flat non-summer rate. Consequently, only half of the Tier 2 usage reported in June is subject to the elasticity reaction associated with Tier 2 usage. By comparing the actual revenues billed for Tier 2 with the revenues that would have been generated if all of the Tier 2 usage were billed at the Tier 2 rate, I could determine how much of the Tier 2 usage was not billed at the Tier 2 rate. Once I determined how much of the Tier 2 usage was not billed at the Tier 2 rate, I had to normalize that component of the Tier 2 usage for the price elasticity impact that the Tier 2 price would have created.

Third, adjustments were made to capture differences in the average number of days billed for each bill.

Fourth, adjustments were made to capture differences in economic conditions, as reflected in the year-over-year differences in Public Service's usage forecasts.

Fifth, adjustments were made to capture differences between the forecasted and actual impacts of Demand Side Management on usage.

Sixth, adjustments were made to capture the impacts of the year-over-year increases in the deployment of photovoltaic solar panels behind the meter under Public Service's Solar Rewards® program.

Q. PLEASE SUMMARIZE YOUR FINDINGS AFTER ADDING 2013 TO THE ANALYSIS AND UPDATING THE 2010 THROUGH 2012 RESULTS.

A. Table DEG-3 below summarizes my findings with respect to reductions to energy consumption and system peak demand. For 2010-2012, I show both the preliminary results shared with the Commission during the CIM and the modified results based on the methodological improvements I described above. I compare these updated estimates with the predicted reductions provided in the 2009 Electric Phase II Rate Case. As can be seen from Table DEG-3, the estimated annual reductions to the residential system coincident peak ("CP") demand were similar to the 2009 Electric Phase II Rate Case CCOSS Study prediction.

TABLE DEG-3

09AL-299E CCOSS Study Prediction			
Energy Consumption: -3.65%		Megawatt Reduction: -51	
Preliminary (Reported to Commission on 1/22/2013)	Final (Reported in this Filing)	Preliminary (Reported to Commission on 1/22/2013)	Final (Reported in this Filing)
2010 Actual			
-1.89%	-2.18%	-25	-31
2011 Actual			
-4.35%	-3.44%	-60	-50
2012 Actual			
-3.38%	-3.56%	-53	-47
2013 Actual			
2013 not in preliminary report	-4.49%	2013 not in preliminary report	-65

Q. PLEASE EXPLAIN YOUR METHODOLOGY FOR DETERMINING HOW THE IBR AFFECTED SYSTEM PEAK DEMAND.

A. Public Service used the same methodology for calculating the actual IBR impact on CP demand that The Brattle Group used in the 2009 Electric Phase II Rate Case. The Brattle Group assumed a 75 percent coincidence between a residential customer's non-coincident peak ("NCP") demand and the Company's system CP. The Brattle Group also used non-coincident load factors ranging from 55 percent to 64 percent for the four summer months. The Brattle Group vetted both the assumed coincidence factor and monthly load factors with the Company, and the Company agreed to their use. By applying the load factors to the usage reductions from the elasticity impact, the change in NCP was determined. The resulting NCP was then multiplied by 75 percent to obtain the associated impact on the Company's system peak demand. The specific Brattle Group formula is as follows:

Change to System Peak = Change in NCP times 75%

Change in NCP = Change in Usage **divided by**: [days in the month times 24 hours times the monthly **summer** load factor]

Q. HAVE YOU PREPARED AN ATTACHMENT THAT SUMMARIZES THE UPC NORMALIZATION RESULTS BY MONTH FOR EACH YEAR?

A. Yes. Please see Attachment DEG-1, "Four Year UPC Summary."

Q. PLEASE SHOW HOW ATTACHMENT DEG-1 DEMONSTRATES THE IMPACT OF EACH NORMALIZATION FACTOR.

A. Please refer to the column headings in Attachment DEG-1, which identify the normalization factors. Using the actual year 2010, I have repeated below the resulting change to the actual UPC in kWh attributable to each normalization factor.

- E-Factor (differences in the percent of price change): 3.1
- Current Period Weather Normalized: (18.1)
- Tier 2 usage in the Summer Month billed at the Tier 1 rate: (0.5)
- Billing Days Differences: (0.3)
- Billing Cycles Differences: 2.1
- Economic Forecast – Base versus Current Year: (14.3)
- DSM – Actual versus Forecast: 2.3

- Adjustment for Solar Rewards®: 1.0
- Current Period to Test Period Normalized: (17.5)

Q. HAVE YOU PREPARED ATTACHMENTS THAT DEMONSTRATE THE FORMULA DETAILS FOR EACH OF THE ABOVE DESCRIBED ADJUSTMENTS?

A. Yes. Attachment DEG-2, "E- Factor Formulas," shows these calculations and results for the E-Factors and E-Factor differences. Attachment DEG-3, "All Other Formulas," does the same for all of the other adjustments.

Q. HAVE YOU PREPARED A SUMMARY ATTACHMENT THAT SUMMARIZES THE AMOUNT OF UPC ADJUSTMENT PER NORMAIZATION ITEM?

A. Yes. Please see Attachment DEG-4, "Normalization Summary."

Q. HAVE YOU PREPARED AN ATTACHMENT THAT DETAILS THE ENERGY AND PEAK IMPACTS BY EACH SUMMER MONTH FOR EACH YEAR THAT INCLUDES THE SUMMARY CALCULATIONS THAT YOU PRESENTED EARLIER IN YOUR DIRECT TESTIMONY?

A. Yes. Please see Attachment DEG-5, "Tier 2 Peak and Energy Impacts."

Q. WHAT DO YOU CONCLUDE REGARDING THE DIFFERENCES BETWEEN THE UPDATED ESTIMATES OF THE ACTUAL IMPACTS OF IBR WITH THE PREDICTED IMPACTS IN THE 2009 ELECTRIC PHASE II RATE CASE?

A. The estimated actual impacts on usage range from 2.18 percent to 4.49 percent, which bracket the long-run prediction of 3.65 percent. The estimated actual impacts on system peak demand range from 31 MW to 65 MW, which also bracket the long-run prediction of 51 MW. Since customer reaction to a price signal like IBR requires an understanding of the price structure, Public Service is not surprised that the actual IBR impact of 2.18 percent and 31 MW for the first year of implementation was below the predicted impact. The predicted IBR impacts provided in the 2009 Electric Phase II Rate Case represented a longer-term view of expected impacts, rather than the impacts during customers' first year of experience with a new rate structure. The results for 2011, 2012 and 2013 are more representative of the longer-term impact of the IBR, and are consistent with the predicted impact of IBR in the 2009 Electric Phase II Rate Case. Therefore, I conclude that the actual customer responses in 2011, 2012 and 2013 largely confirm the predicted customer response provided in the 2009 Electric Phase II Rate Case.

Q. DO YOU HAVE ANY CONCLUDING COMMENTS REGARDING YOUR IBR ANALYSIS?

A. Yes. It is very difficult to identify, quantify, and eliminate (normalize) every impact on a customer's usage that *is not* related to their reaction to the price signal -- so as to identify the portion of any change that *is* attributable to that signal. Public Service is not aware of any other study that has attempted to directly isolate such an impact using actual utility usage records on an entire residential customer class of well over a million customers. Because not all causal factors have been identified or precisely measured, our estimates are subject to uncertainty. Nevertheless, the results seem to largely validate the previous predictions.

III. THE REVENUE IMPACT OF TIME OF USE ("TOU") RATES

Q. WHY ARE YOU PRESENTING AN ANALYSIS OF THE REVENUE IMPACT OF COMMERCIAL AND INDUSTRIAL ("C&I") TOU RATES?

A. The C&I TOU rates were introduced as pilot tariffs in 2010. In its Decision No. C10-0286 in the 2009 Electric Phase II Rate Case, the Commission ordered Public Service to review the revenue impact of these pilot tariffs[3].

Q. WHAT IS THE PURPOSE OF TOU RATES?

A. The goals of TOU rates are to send better price signals and recover costs more equitably from the customers imposing those costs.

Q. ARE THE IMPACTS OF TOU PRICE SIGNALS SIMILAR TO THE IMPACTS OF IBR PRICE SIGNALS DISCUSSED PREVIOUSLY?

A. No. Although the general principles of price elasticity apply, there are several reasons why the reaction of C&I customers to TOU price signals are likely to be significantly different from residential customers' reactions to IBR price signals. Consequently, I decided not to apply the residential price elasticity impacts discussed above to the TOU rates offered to large C&I customers. I elaborate on these reasons later in my Direct Testimony.

Q. PLEASE DESCRIBE THE PILOT TARIFFS INTRODUCED IN 2010.

A. Four tariffs were introduced. The first is Schedule STOU, which is available to customers served under Schedule SG. The second is Schedule SPVTOU, which is available to customers served under Schedule SG that have deployed

[3]Decision No. C10-0286 at ¶ 65.

photovoltaic solar panels behind the meter under the Company's Solar Rewards® program. The third is Schedule PTOU, which is for customers served under Schedule PG. The fourth is Schedule TTOU, which is for customers served under Schedule TG.

Q. DID THE PILOT PROGRAM LIMIT THE LEVEL OF PARTICIPATION?

A. Yes. The tariff language states that "this pilot program is limited to a total of 20 MW of maximum annual measured demands for customers on Schedules STOU, PTOU or TTOU." (See Schedule STOU of the Company's Tariff filed December 1, 2014, and effective January 1, 2015, under Advice Letter No. 1682.) For those customers served under Schedule SPVTOU, the limit is annually determined based on the Renewable Energy Standard Adjustment ("RESA") plan approved by the Commission. The limit for 2016 is 12 MW.

Q. HOW MANY CUSTOMERS PARTICIPATE IN THE TOU PROGRAMS?

A. There are currently 2 Schedule STOU customers, 88 Schedule SPVTOU customers, 2 Schedule PTOU customers and 0 Schedule TTOU customers.

Q. DO THESE CUSTOMERS HAVE ON AND OFF PERIOD USAGE LEVELS THAT ARE TYPICAL OF CUSTOMERS ON SCHEDULES SG AND PG?

A. No. The TOU customers who have selected this pilot offering have a much higher percentage of off-peak energy use.

Q. CAN YOU EXPLAIN WHY THESE CUSTOMERS HAVE DIFFERENT USAGE CHARACTERISTICS?

A. Yes. Optional TOU tariffs are subject to “self-selection.” In other words, customers will choose an alternative tariff because the rate structure reduces their bills even if they do not change the levels or patterns of their usage. Specifically, customers who have a higher percentage of off-peak usage than the typical customer have an immediate opportunity to reduce their total bills without any response to the price signal. It appears that a few relatively large customers saw this self-selection opportunity and captured the pilot’s maximum MW allocation. This is demonstrated by the fact that the four Schedule STOU and PTOU customers subscribed quickly and absorbed the MW limit for the service. A similar self-selection process appears to have occurred for the SPVTOU, where each annual limit rapidly filled. There are currently 88 Schedule SPVTOU customers. In addition, the results of my analysis show a significant reduction to Public Service’s revenues, which would suggest such self-selection.

Q. WHAT YEARS DID YOU ANALYZE TO DETERMINE THE REVENUE IMPACTS?

A. I analyzed the years 2013 and 2014.

Q. PLEASE SUMMARIZE YOUR FINDINGS

A. My findings are summarized in Table DEG-4 below.

TABLE DEG-4

		Actual TOU Revenue	Revenue if under Standard Tariff	Revenue Difference	Revenue % Difference
STOU	2013	$ 532,464	$ 668,719	$ (136,255)	-20.38%
	2014	$ 546,455	$ 668,812	$ (122,357)	-18.29%
PTOU	2013	$ 2,936,840	$ 4,333,131	$ (1,396,291)	-32.22%
	2014	$ 2,900,583	$ 4,481,646	$ (1,581,064)	-35.28%
SPVTOU	2013	$ 3,756,326	$ 4,401,551	$ (645,225)	-14.66%
	2014	$ 5,910,542	$ 7,010,779	$ (1,100,237)	-15.69%
2 Year Total		$ 16,583,210	$ 21,564,639	$ (4,981,429)	-23.10%

Please note that in 2013 and 2014 TOU customers contributed about $5 million less in total revenue (or 23 percent less) than they would have contributed under standard tariffs.

Q. WHAT STEPS DID YOU TAKE TO CALCULATE THE REVENUE IMPACT?

A. For each year, I derived revenues under the standard tariffs by applying the rates in the standard SG and PG schedules to the TOU customers' usage and demand billing determinants. I then compared these hypothetical revenues to the actual revenues that the Company billed under the TOU schedules.

Q. YOU INDICATED THAT THE PURPOSE OF IBR AND TOU RATES IS TO SEND PRICE SIGNALS THAT MAY RESULT IN A MORE EFFICIENT USE OF ENERGY. DID YOU CONSIDER ANALYZING THE ELASTICITY IMPACTS FROM TOU RATES LIKE YOU DID FOR THE RESIDENTIAL IBR?

A. Yes. Given that the purposes of IBR and TOU rates are similar, I did consider such an analysis. However, I was unable to determine the extent to which the

TOU customers responded to the TOU price signals, or even if they responded at all. The reasons for my uncertainty are discussed below.

First, when considering such an analysis, it is important to understand the complexity of TOU price signals and to have a methodology for measuring actual results that can capture that complexity. Neither the Company nor the utility industry, to my knowledge, has developed such a methodology. Such a methodology requires the measurement of the three elasticity reactions to TOU rates. Customers would tend to reduce their consumption in response to the higher on-peak rates similar to the predicted response of customers to the Tier 2 IBR rates. Customers would tend to increase their usage in response to the lower off-peak rates, similar to the predicted response of customers to the Tier 1 IBR rates. A TOU customer can also choose to shift usage from the daily on-peak period to the daily off-peak period. This shift could reduce total system costs, even if the customer's total usage did not change. Without a methodology for measuring all three potential elasticity reactions, the resulting analysis could be very misleading.

Second, the only known elasticity estimates available to Public Service are the estimates provided by The Brattle Group for IBR. These elasticities were derived from residential TOU pilots that were conducted by the Company. There are several reasons why these residential elasticity estimates are not applicable to C&I customers, including the following:

- Reactions to price signals (elasticity) are heavily dependent upon the degree to which the use of the product in question is discretionary or can be shifted to another period. The fact that the electricity used by C&I customers includes their energy needs for product production reduces their willingness to curtail or shift usage, since these responses could reduce profits. In other words, the demand curve for C&I customers is likely to be more inelastic than the demand curve of residential customers.
- Elasticities are heavily dependent upon what is called "income elasticity," which represents the percentage of total income attributable to energy expenses and heavily influences the level of elasticity. The cost of energy as a percentage of total income can vary significantly among C&I customers and between residential and C&I customers in general. Such differences raise two problems. First, applying residential elasticities to C&I customer is a dubious practice. Second, applying one elasticity estimate to all C&I customers is also a questionable practice.
- Customers participating in the TOU pilot program represent a small subset of the C&I customer population, particularly since customers who stood to benefit the most from the rate structure rushed to enroll.
- Customers on the TOU schedules have reduced their overall bills by 16 percent to 35 percent. When customers recognize significant

"windfall gains" by converting to a new rate structure, they may have much less incentive to consider additional usage changes in response to the price signals.

Q. WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS?

A. An opt-in TOU tariff allows customers with high percentages of off-peak energy use to reduce their bills without changing the levels or patterns of their usage. Since the participating customers realize significant bill reductions without responding to the price signal, their interest in responding to the price signal is diminished.

IV. THE IMPACT OF THE DISTRIBUTION DEMAND RATCHET ON DISTRIBUTION DEMAND BILLING DETERMINANTS AND REVENUES

Q. WHY ARE YOU SUBMITTING A RATCHET IMPACT ANALYSIS?

A. In the 2009 Electric Phase II Rate Case, the Commission approved a 50 percent Distribution Demand Ratchet for Schedules SG and PG. This analysis has three purposes. The first is to identify how much revenue was generated from the demand ratchet. The second is to analyze the number of customers affected by the ratchet and the impact on their billing demands. The third is to estimate the additional revenue that could be generated from a (hypothetical) 100 percent demand ratchet.

Q. HOW MUCH REVENUE WAS GENERATED FROM THE DEMAND RATCHET?

A. The Distribution Demand Ratchet generated $3,496,775 under Schedule SG and $780,938 under Schedule PG in calendar year 2013.

Q. HOW MANY CUSTOMERS WERE AFFECTED BY THE RATCHET AND WHAT WAS THE IMPACT ON THEIR BILLING DEMANDS?

A. A total of 12,626 Schedule SG customers and 141 Schedule PG customers were affected. The ratchet increased the billing demands of Schedule SG customers by 722,474 kW and the billing demands of Schedule PG customers by 196,216 kW.

Q. WHAT ADDITIONAL REVENUE WOULD HAVE BEEN GENERATED FROM A HYPOTHETICAL 100 PERCENT DEMAND RATCHET?

A. With a 100 percent ratchet, an additional $38,501,409 would have been generated from SG customers and an additional $5,263,321 would have been generated from the PG customers in 2013.

Q. PLEASE EXPLAIN THE METHODOLOGY USED.

A. A database was extracted from the Company's billing system of all existing Schedule SG and Schedule PG customers. From this data I compared the impacts of the ratchet on the billing demands and revenues for Schedules SG and PG.

Q. DID YOU ALSO COMPARE BILLING DEMANDS AND REVENUES RESULTING FROM A HYPOTHETICAL 100 PERCENT DEMAND RATCHET VERSUS A SCENARIO WHERE NO DEMAND RATCHET IS APPLIED?

A. Yes. The difference in Schedule SG billing demands under the two scenarios is 8,677,196 kW, or a difference of 26.5 percent. For Schedule PG the difference is 1,518,658 kW, or 21.5 percent. The corresponding differences in revenues for Schedule SG and Schedule PG are about $42 million and $6 million, respectively.

Q. HAVE YOU PREPARED AN ATTACHMENT THAT SHOWS YOUR RATCHET ANALYSIS AND CALCULATIONS?

A. Yes. Please see Attachment DEG-6, "Ratchet Analysis Results."

V. AN EXPLANATION OF HOW BILL FREQUENCY DISTRIBUTION STUDIES WERE USED TO DETERMINE THE PROPOSED GRID USE CHARGE FOR THE R AND C RATE SCHEDULES

Q. WHAT IS THE PURPOSE THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In his Direct Testimony, Mr. Scott Brockett discusses the proposed Grid Use Charges for Schedules R and C and the associated usage intervals. In this section of my Direct Testimony, I explain how the associated usage intervals and rates were developed.

Q. PLEASE EXPLAIN THE DATA SOURCE THAT THE COMPANY USED TO DEVELOP THE INTERVALS FOR THE GRID USE CHARGE.

A. The Company conducted a special study of the distribution of bills by level of usage for the year 2013 for customers under Schedules R and C. Such a study is sometimes called a “bill frequency distribution study.” The data source for these studies is the Company’s billing system.

Q. WHAT WAS THE STRUCTURE OF THE BILL FREQUENCY DISTRIBUTION STUDY?

A. The study identified the number of customers whose monthly usage fell within specified bands, and the total usage of these customers by band. The Company identified the number of customers in 100 kWh increments up to 2,201 kWh, after which we identified customers in 200 kWh increments up to 4,000 kWh. All monthly usage greater than 4,000 kWh was included in a single increment. By dividing the total usage in each increment by the total customers in the increment, the average usage per customer for each increment could be obtained. Table DEG-5 below provides a sample from the study that will illustrate this point.

Table DEG-5

Monthly Increment Bands	100 to 200	201 to 300	301 to 400	401 to 500
Study Count	1,067,846	1,490,607	1,640,718	1,607,834
Study Usage	165,353,424	375,737,374	575,440,367	723,447,122
UPC	155	252	351	450

Q. WHERE THERE ANY ADJUSTMENTS TO THE USAGE PER CUSTOMER OR TO THE PERCENTAGE OF CUSTOMERS IN EACH OF THE BANDS?

A. Yes. The study results had to be normalized to the CCOSS number of customers, total usage and the associated UPC. This normalization included some shift of the usage and number of customers in each band. Table DEG-6 below identifies the differences between the study data, which needed to be normalized, and the CCOSS data.

Table DEG-6

Residential		Small Commercial	
Study Usage	***CCOSS Usage***	***Study Usage***	***CCOSS Usage***
9,516,788,818	8,880,334,513	1,366,734,235	1,291,698,728
Study Count	***CCOSS Count***	***Study Count***	***CCOSS Count***
13,903,396	14,133,047	1,246,023	1,305,443
Usage per Customer			
684	628	1,097	989
Study Number of Bills as a % of CCOSS Number of Bills			
98%		95%	
Study Usage Count as a % of CCOSS Usage Count			
107%		106%	
Study Usage per Customer as a % of CCOSS Usage per Customer			
92%		90%	

Q. HOW DID YOU DETERMINE THE FIXED CHARGE AMOUNT FOR EACH BAND OR USAGE INTERVAL?

A. There were five steps. First, I identified the Distribution Revenue Requirement for Schedules R and C from the CCOSS sponsored by Company witness Ms. Basquez.

Second, from the normalized bill frequency study I determined the percentage of the total Schedule R and C usage in each band.

Third, from the normalized bill frequency study I allocated the Schedule R and C total bills among the bands.

Fourth, I calculated the distribution costs that should be recovered from customers in each band based on its percentage share of total class usage.

Fifth, I divided this allocated revenue requirement for each band by the total annual bills in the same band to derive the Grid Use Charge for that band. The following table shows the calculations for each rate schedule:

Table DEG-7

R Rate Schedule			
Monthly Usage Bands	**Distribution Cost per Band**	**Annual Number of Bills per Band**	**Fixed Monthly Charge**
0 to 200	$ 4,340,917	1,658,659	$2.62
201 to 500	$ 37,396,259	4,817,439	$7.76
501 to 1,000	$ 81,919,540	5,625,946	$14.56
1,001 to 1,400	$ 28,287,200	1,101,190	$25.69
> 1,400	$ 41,644,006	929,813	$44.79
Total Distribution Cost	**$ 193,587,922**		

C Rate Schedule			
Monthly Usage Bands	**Distribution Cost per Band**	**Annual Number of Bills per Band**	**Fixed Monthly Charge**
0 to 500	$ 2,702,447	628,839	$4.30
501 to 1,000	$ 3,330,168	238,547	$13.96
1,001 to 1,700	$ 5,038,622	199,766	$25.22
1,701 to 3,000	$ 6,796,639	155,705	$43.65
> 3,000	$ 7,603,423	82,586	$92.07
Total Distribution Cost	**$ 25,471,298**		

Q. HAVE YOU PREPARED AN ATTACHMENT THAT SHOWS THE CALCULATIONS FROM WHICH THE RESULTS IN TABLE DEG-7 ABOVE WERE DERIVED?

A. Yes. Please see Attachments DEG-7 and DEG-8.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Donald E. Garretson

I received a Master of Arts in economics in 2013 from Regis University specializing in the economics of Global Sustainability, a Bachelor of Science degree in economics in 1966 from the University of Tennessee, and engaged in doctoral studies in economics at the University of Washington from 1966 through 1968.

I served as an officer in the US Army from 1962 through 1965.

I began my civilian career with the Boeing Company as an aerospace major subcontract cost analyst for four years. I left to work for AT&T from 1970 to 1991, beginning in economic forecasting as a first line manager, promoted to second level as a manager of cost, rates, and rate structures, with particular focus on new long distance rates and rate designs and the pricing of new terminal end user PBX and single telephone products. In that role, I conducted price elasticity and cross elasticity analyses for Pacific Northwest Bell, and then subsequently for AT&T headquarters where my elasticity and product pricing models were adopted across the Bell System.

In 1982, I was promoted to director and was assigned to AT&T headquarters in Basking Ridge, where I led the cost analysis effort for Billing Services in anticipation of the 1984 divesture of the Baby Bells from AT&T Long Lines.

In 1986, I was promoted to executive director of account management for Bellcore, the Bell Labs arm of the Baby Bells.

From 1992 to 2005, I left AT&T to work for a series of telecom startups as a vice president of sales, marketing and product development, culminating as the North

American vice president of sales and marketing for the optical switch products of Marconi out of the UK. In these executive roles, I also provided new product pricing and market segmentation analysis for several new products, such as the voice recognition chip, fax and voice over IP, wireless central offices, and broadband code division wireless cell phone communication.

I began my career with Xcel Energy in June 2006 as a price analyst in the marketing department, and was subsequently assigned to the regulatory department where I currently work. I also currently teach microeconomics and macroeconomics at the Community College of Denver ("CCD") and am a guest lecturer in economics at the University of Tennessee.

In my current capacity at Xcel Energy I created the tariff, rates and rate design for Public Service's "Solar Rewards Community Service" product offering, and worked with the Brattle Group in conjunction with its contracts with Public Service regarding IBR and Demand Response products. I was also the Company's expert witness in New Mexico when the "Saver Switch" and Interruptible Service Option Credit ("ISOC") tariffs were introduced. In addition, I have provided back-up analysis for decoupling, demand response offerings such as Critical Peak Pricing ("CPP") and Time of Use ("TOU"), and for solar and battery storage future alternatives. I also support various regulatory initiatives, such as annual rider filings and associated reports to the Public Utility Commission.