Decision No. C05-0412

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 04S-164E

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY WITH ADVICE LETTER NO. 1411 - ELECTRIC.

ORDER REGARDING ELECTRIC RATES

Mailed Date: April 11, 2005
Adopted Date: March 17, 2005

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I. BY THE COMMISSION

A. Statement

1. This matter has its origin in Commission Decision No. C00-0393 in Docket No. 99A-377EG. There, the Commission approved a Stipulation and Settlement Agreement entered into by the parties regarding Public Service Company of Colorado's (Public Service or Company) application for approval of the merger of New Centuries Energies, Inc. and Northern States Power Company. That Settlement Agreement provided for Public Service to file a Phase II electric rate case within 120 days of the conclusion of its 2002 Phase I rate case.

2. This is the cost allocation or Phase II portion of Public Service's rate case. The Phase I portion was finalized through a Settlement Agreement approved by the Commission in Decision No. C03-0670 issued June 26, 2003 and Decision No. C03-0877 (Decision on Rehearing, Reargument, or Reconsideration) issued August 8, 2003 in Docket No. 02S-315EG.

Public Service filed Advice Letter No. 1411 – Electric, and accompanying tariffs on March 26, 2004. Public Service filed its Direct Testimony and Exhibits supporting its Advice Letter filing on the same day.

3. Public Service indicated that the purpose of the Advice Letter filing was to place into effect new base rates which would replace the currently effective base rates and eliminate the Phase I General Rate Schedule Adjustment rider that was placed into effect pursuant to Decision No. C03-0670 in Docket No. 02S-315EG.

4. As part of its direct case, the Company proposed several changes to its existing rate classes, structures, and amounts. Specifically, it proposed to implement a zero-based Electric Commodity Adjustment (ECA) and ECA Factors that would replace and supersede the currently effective ECA Factors. The Company proposed that the costs associated with fuel and purchased energy would be removed from base rates and recovered through the ECA. According to Public Service, it was therefore necessary to increase the Fort St. Vrain Decommissioning rider and the Demand Side Management Adjustment rider as a result of removing fuel and purchased energy costs from base rates.

5. Public Service proposed allocating costs to customer classes and structuring the resulting rates to, according to Public Service, reflect the costs incurred in providing service to each class of customers. Additionally, Public Service proposed rates it represented would encourage customers to make more efficient use of the Company's production resources by proposing to seasonally differentiate the base rates between summer and winter seasons, and to implement the Interruptible Service Option Credit (ISOC) proposal. Public Service also proposed to recover any monthly credits paid to customers under a new interruptible tariff (Schedule ISOC) through the proposed Purchased Capacity Cost Adjustment (PCCA). At the

time of its Phase II filing, Public Service's proposed PCCA filing was pending before the Commission. Finally, Public Service requested that the tariffs accompanying Advice Letter No. 1411 become effective on April 26, 2004.

6. Intervenors in this matter included Commission Staff (Staff); the Colorado Office of Consumer Counsel (OCC); Black Hills Colorado, LLC (Black Hills); Kroger Co. (Kroger); the Federal Executive Agencies (FEA); Western Resources Advocates (WRA); Colorado Energy Consumers (CEC); the City and County of Denver (Denver); the Colorado Municipal League (CML); the Denver Building Owners and Managers Association (BOMA); the University of Colorado at Boulder (CU); and Climax Molybdenum Company (Climax) and CF&I Steel L.P. (CF&I). The late-filed Petitions to Intervene of Kenneth Regelson (Regelson); City of Boulder (Boulder); and City of Lakewood were granted. Generally, the Intervenors took issue with some of the individual cost allocation and rate design proposals of the Company.

7. While Public Service defended some of its proposals in its rebuttal testimony, the Company accepted intervenor proposals in several areas, including: rate design of the service and facility charges for the Small Commercial (Schedule **C**) and Secondary General (Schedule **SG**) service rates, ISOC, and standby service; net metering, rider rate design, and ECA; and general tariff language revisions. These issues are described and analyzed in detail below.

8. In order to determine whether Public Service's proposed tariffs result in rates that are just and reasonable, we must allocate costs among customer classes to ensure that the revenue generated by each class is equal to the cost of serving that class. This difficult process is exacerbated by the fact that Public Service last filed a Phase II rate case more than ten years ago. This requires that the proposed tariffs, as well as the settlements entered into by the parties, be

subjected to careful analysis. We commend all the parties in this matter for their extensive work and analysis.

II. PROCEDURAL HISTORY

9. As discussed *supra*, on March 26, 2004, Public Service filed Advice Letter No. 1411 – Electric along with supporting testimony and exhibits. Public Service requested an effective date of April 26, 2004. In Decision No. C03-0670,[1] we approved a Settlement Agreement that authorized Public Service to place into effect a General Rate Schedule Adjustment Rider (GRSA) designed to reduce total annual electric base rate revenues by $21,082,702.[2] As a result, Advice Letter No. 1411 – Electric proposes new electric base rates to replace the GRSA.

10. By Commission Decision No. C04-0364, pursuant to § 40-6-111(1), C.R.S., we set the proposed tariffs for hearing and suspended their effective date until August 24, 2004, or until further order of the Commission, to determine whether the rates, terms, or conditions contained therein were proper.

11. On June 10, 2004, we held a pre-hearing conference in this matter. Appearances were entered on behalf of Public Service, Staff, OCC, Kroger, Black Hills, FEA, WRA, CEC, Denver, CML, BOMA, CU, Climax, and Boulder. We granted the late-filed petitions to intervene of Boulder and Regelson. The parties first proposed two alternative procedural schedules, but ultimately mutually agreed to a procedural schedule that set a hearing in this matter for January 10 through 14, 18 through 21, and 24 through 28, 2005. A technical

[1] These issues were additionally addressed and modified to some extent in Decision No. C03-0877 on rehearing, reargument, and reconsideration.

[2] As part of Decision No. C03-0670, we also ordered Public Service to reduce total annual gas base rate revenues by $17,843,528 and to increase thermal base rate revenues by $880,653 through other GRSAs.

conference was scheduled for June 21, 2004 and Statements of Position were due on February 11, 2005. Decision No. C04-0704 memorialized the procedural schedule.

12. On July 15, 2004, we issued Decision No. C04-0777 in response to Public Service's filing of Advice Letter No. 1411 – Electric – Amended. Public Service made this filing to change the proposed effective date of the tariff sheets from April 26, 2004 to September 2, 2004, to allow adequate time for the Commission to issue a decision in this matter. Consequently, by that Order, we amended the 120-day suspension period for the proposed tariff sheets to December 31, 2004, pursuant to § 40-6-111(1), C.R.S.

13. On December 23, 2004, we granted Public Service's Motion for Leave to File Supplemental Direct Testimony. As part of that Order, we also gave Intervenors until January 3, 2005 to file any Supplemental Answer Testimony responding to the Company's Supplemental Direct Testimony. We further allowed Public Service to present oral Rebuttal Testimony, limited to the issues raised in any Supplemental Answer Testimony during the hearing.

14. Pursuant to the directives in Decision No. C03-0704, we conducted hearings on the Phase II rate case on January 18 through 27, 2005.[3] During the hearings, several of the parties entered into settlement negotiations. A settlement was reached regarding the Company's ISOC with those Intervenors who addressed the proposal in their Answer Testimony. Settlements were also reached with several Intervenors regarding the Company's Net Metering/Net Billing and Windsource proposals. Public Service also entered into a settlement agreement with Staff and the OCC regarding the removal of fuel and purchased energy costs from base rates and cooperation in the future development of a time-of-use (TOU) fuel and

[3] We vacated the January 10 through 14, 2005 hearing dates to allow parties to conduct settlement negotiations.

purchased power recovery mechanism. A hearing on the settlements was held on February 2, 2005.

15. On February 17, 2005, we issued Decision No. C05-0207. In that Order, we granted a Motion for Enlargement of Time Within Which to File Closing Briefs, filed by CEC to the close of business on February 15, 2005. CEC indicated that the enlargement of time was to be applicable to all parties to the docket. CEC's filing was addressed at the Commissioners' Weekly Meeting on February 15, 2005. However, immediately following that Meeting, Public Service filed a Motion for Extension of Time to File Statements of Position. Public Service sought until the close of business on February 18, 2005 for all parties to file their Statements of Position. As part of that filing, Public Service agreed to file an Amended Advice Letter extending the 210-day deadline by 2 weeks or until April 15, 2005, in order to accommodate the Commission's need for additional time to consider the Statements of Position and conduct deliberations, which were previously scheduled for March 3, 2005.

16. At a Special Commissioners' Deliberation Meeting held at 7:00 p.m. in Grand Junction, Colorado, on February 15, 2005 we granted the motion contingent upon Public Service filing an Amended Advice Letter as described above.

17. On February 18, 2005, Public Service filed Advice Letter No. 1411 – Electric – Second Amended, which changed the proposed effective date of the tariff sheets from September 2, 2004 to September 17, 2004. As a result, the Commission, in Decision No. C05-0253 (issued March 2, 2005) amended the 210-day suspension period for the proposed tariff sheets to April 15, 2005.

18. The Commission held deliberations on the contested issues, as well as the settled issues on March 17, 2005. Now, being duly advised in the matter, we approve the various Settlement Agreements and adopt the rate design consistent with the discussion below.

III. CONTESTED ISSUES

A. Seasonal Rates

19. Public Service proposed to seasonally differentiate the production cost component of its base rates because it contends that its production costs are higher in the summer months when its customers' demand is at its highest. According to the Company, because the price of power moves with demand, the seasonal rate proposal would better reflect the way in which it incurs its costs of power supply. Company witness Mr. Darnell asserts that the seasonal differentiation is economically more efficient than pricing all hours in all months the same, because the consumer is sent a price that signals that the Company requires more investment to serve a greater level of demand during the summer period. Under Public Service's proposal, the summer period would encompass the months of June through September.

20. According to Company witness Mr. Zins, historically Public Service's system peak loads were very similar from season to season. However, beginning in the 1990s, the summer peak began growing faster than the winter peak. He maintains that the current forecasts indicate the trend will continue. Under the Company's proposal, the seasonal differentials are based on differences in the fixed-cost component of the power supply revenue requirement. Public Service's starting point in establishing the seasonal differentials was to set a one-cent differential for the Residential (**R**) class. This differential was then used to develop "cost-equivalent" differentials for other classes based on their corresponding load characteristics. For example, the Small Commercial (**C**) class would pay an additional 1.202 cents per kWh

consumed during the summer months.[4] As a check to the reasonableness of the one-cent adder, the Company performed an analysis of the costs of a new combustion turbine unit to provide power. That analysis showed that the adder for the **R** class would be 1.6 cents per kWh. Based on that analysis, Public Service concluded that its one-cent adder was a conservative amount.

21. None of the parties opposed the *general concept* of seasonal differentiation. However, there is a dispute over the amount of the differentiation, as reflected in rates. Staff witness Dr. Schmitz stated that Public Service is projecting that its ratio of summer to winter peak demands will be 1.2:1 by 2008. He notes that the Commission has previously found that it is appropriate for a utility to have seasonal rates when the ratio of summer to winter peak demands reach 1.2:1 for a period greater than two years.[5] In order to develop its seasonal rates, Staff proposed a two-period (summer/winter) Average and Excess Demand (AED) cost allocation method. Under Staff's allocation method, the first step is to classify Production costs as either summer or winter, based on a ratio of seasonal peak (54.19 percent summer and 45.81 percent winter). The Production costs of each season were then further allocated to rate classes using the AED allocator (single seasonal CP/seasonal class NCP). The Staff proposal results in the **R** class paying an additional $0.00514 per kWh consumed during the summer months (June to September) while the **C** class would pay an additional $0.01023 per kWh consumed during the summer months.[6]

[4] Classes that are billed based on a kW-month basis would have their respective demand charges increased during the summer months. For example, customers taking service under the Transmission General (**TG**) rate would pay an additional $3.61 per kW in the summer as compared to the winter. Customers taking service under the Secondary General (**SG**) rate would pay an additional $3.77 per kW in the summer, as compared to the winter.

[5] *See* Hearing Exhibit 90, Decision No. C79-1111, page 125.

[6] *See* Hearing Exhibit 63, Exhibit WLW-5, Schedule 10, CORRECTED JANUARY 3, 2005, for a complete listing of Staff's rate design proposal.

22. Through its witness Mr. Binz, BOMA advocated a smaller seasonal differential as compared to the Company. Under Public Service's seasonal method, the seasonal differential component for the production-related costs of a Secondary General (**SG**) customer would be 1.56.[7] Under Mr. Binz's method the seasonal differential component for the production-related costs of a **SG** customer would be either 1.10 if the summer period was the four months the Company proposed or 1.20 if the summer period was only July and August.[8] Mr. Binz felt that a ratio of 1.56 was too large because, in his opinion, it does not cost the Company 1.56 times more to serve customers in the summer as compared to the winter.

23. We agree with the parties that it is now appropriate to implement seasonal rates for Public Service. During the last several years the demand on Public Service's system has increased faster for the summer months than for the remaining months of the year. Public Service projects that this trend will continue. It is reasonable to assume that the Company's costs will also increase to support this trend. We agree that, without some sort of price signal, it is likely customers will not change their usage patterns. While seasonal rates will not provide as effective a price signal as time-of-day rates, we are nonetheless willing to approve seasonal rates as one step toward addressing the problem.

24. Of the alternatives presented regarding seasonal differentials, we find BOMA's method most compelling. The BOMA method upholds our policy that rates should be based on actual costs, and we believe it better addresses the forecasted trend of increased usage of combustion turbines as shown in Mr. Zins' Exhibit PJZ-3, page 2 of 2. Two proposed summer

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[7] *See* Hearing Exhibit 11 Exhibit RAK-7 page 1 of 3, lines 30 and 31. The summer demand charge for an SG customer is $10.49 per kW-Mo and the winter demand charge is $6.72 per kW-Mo.

[8] Mr. Binz did calculate rates for the **PG** customers and the **TG** customers using his 1.10 ratio, but he did not calculate rates for any of the other remaining rate classes.

periods for seasonal rates have been proposed: two months (July and August), or four months (June through September). Mr. Zins' Exhibit PJZ-2 for the years 1994 to 2009 indicates that the summer peak occurred in June in the years 1996 and 1997. Exhibit PJZ-2 also indicates that June was the second highest summer month peak load in the years 1994 and 2001 and June was the third highest summer month peak load in ten other years. Because the Company contends that its system is moving to more of a summer peaking system, we closely examined the forecasted peak loads for the years of 2004 to 2008 in Mr. Zins' Exhibit PJZ-2.[9] This revealed that the five-year average comparison of September's peak to the system's winter peak produced a ratio of 1.06 to 1. Based on the Commission's finding in Decision No. C79-1111 that seasonal rates make sense when the ratio between the two periods is 1.2:1 or more over a two-year period of time, we conclude that September should be excluded as part of a summer period for seasonal rates. Therefore, we reject Public Service's proposal to include seasonal differentials for September. We also reject BOMA's alternative proposal to apply the seasonal differential only to July and August. In sum, Public Service shall calculate seasonal differentials using BOMA's method reflecting a summer period of the months June, July, and August, based on test year data consistent with the methodology developed in Mr. Binz's Exhibit RJB-4. Because the Commission has adopted a seasonal rate based on a three-month period instead of either the two-month or four-month period proposed by Mr. Binz to develop ratios, we direct the Company to develop a ratio for a three-month period based on the test year data and Mr. Binz's methodology for calculating the summer/winter ratio. We encourage the Company to consult with Mr. Binz as necessary regarding this calculation.

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[9] We excluded the year 2009 because Mr. Zins' exhibit states that the winter period for 2009 only includes October through December.

Upon completion of such calculations, Public Service shall file the updated summer/winter ratio, as well as any workpapers created that detail the methodology utilized, as part of its compliance filing obligations contained within this Order.

25. We do harbor some concern that the resulting seasonal rates will go unnoticed by many customers given that the increase to the overall customer bill may be tiny in the summer months, and the decrease for the remaining months of the year will be correspondingly tiny. We believe that it is important for customers to recognize that their rates are higher in the summer based on a seasonal rate design, not just because of an overall increase in costs of doing business. In this regard, customer education may help alleviate our concern, but the cost to provide that education must be reasonable. Therefore, we require Public Service to educate customers on the implementation and use of seasonal rates. However, we caution Public Service to use every possible means to mitigate expenses and provide customer education at a reasonable cost.[10]

B. Allocation Method for Production, Transmission, and Distribution Substation Costs

26. Public Service proposed continued use of the AED allocation method for the allocation of Production, Transmission, and Distribution Substation fixed capacity costs among the various rate classes. It contended that the use of the AED method is more equitable than a Coincident Peak (CP) or Non-Coincident Peak (NCP) method when a system is comprised of customer classes with widely varying load characteristics, such as Public Service's system.

27. Staff disagrees with the use of the single period AED method for the allocation of Production fixed capacity costs. As discussed *supra*, Staff used a summer/winter AED method

[10] For example, by adding bill stuffers or messages within billing statements.

to develop its seasonal differentials. However, Staff did not take issue with the use of a single period AED method for Transmission and Distribution Substation cost allocations.

28. OCC witness Dr. Stutz recommends using the Peak & Average (P&A) method rather than the AED method. Within his Answer testimony, he provides an example demonstrating why P&A is, in his opinion, more equitable to all customers. He tempers his recommendation for using a P&A method with a concern that, to avoid rate shock, the change over to a P&A method should be gradual. Thus, Dr. Stutz recommends the use of a 20 percent P&A and an 80 percent AED method for the allocation of Production, Transmission, and Distribution Substations. Finally, he points out that Public Service refused to run their Cost of Service (COS) model using a P&A method, so he cannot provide exact figures for the size of the impact, but believes the changes are nonetheless modest.

29. CEC witness Mr. Pollock recommends that the Commission order Public Service to file a COS study using a summer peak allocation method with their next rate case.

30. In his Rebuttal testimony beginning on page 26, Company witness Mr. Keyser disagrees with Dr. Stutz's 20 percent P&A and 80 percent AED method because, in his opinion, using coincident peak demand to allocate system capacity costs can result in "free-riders." Under a CP method, a free-rider would result if a customer had load only during the off-peak periods according to Mr. Keyser. This is because under a CP method that type of customer would receive no allocation of the system's peak for cost allocation purposes. He also disagrees with Mr. Pollock's request for a summer peak allocation cost of service study since any coincident peak allocation method has the free rider problem. Mr. Keyser contends that Staff's seasonalizing of the AED allocation of class excess demand in proportion to an "off-season-

peak" demand is inappropriate and meaningless because, in his opinion, one does not need a seasonalized cost of service study in order to develop seasonal rates.

31. Mr. Keyser goes on to argue that Staff's method isn't mentioned in the NARUC Electric Utility Cost Allocation Manual. He contends that to use a seasonal method, one would require either a detailed analysis of which generation units are used to which portion of the system load (base, intermediate, or peaking), or a detailed analysis of system hourly Loss of Load Probability (LOLP) in order to group similar LOLP values into on-peak, shoulder and off-peak periods, and then allocate production plant costs into these rating periods.

32. In his Rebuttal testimony, Mr. Zins believes the question regarding Staff's allocation method is whether this load ratio is an appropriate basis for allocating cost to the seasons because the seasonal cost distribution for the system is not necessarily proportionate to the load ratio. He contends that Mr. Wendling's seasonal AED allocators are applied to all power plant costs (base, intermediate, and peaking), rather than focusing on peaking plants, which is the plant type with the seasonal cost pattern. Mr. Zins maintains that using this method for seasonal rate design will not accurately reflect class contributions to the system coincident peaks, which is the specific load characteristic that determines the growing need for peaking plant investment.

33. We agree with Public Service that the AED method should be used to allocate Production, Transmission, and Distribution Substation costs. This method has a long precedent of acceptance by this Commission. The testimony regarding this issue has convinced us that the method proposed by the OCC is not an accepted methodology and may cause problems by mixing two methods. Their hybrid method could result in a double counting of costs because the average demand is inherently a part of any measure of system peak.

34. We also reject CEC's recommendation that the Commission require Public Service to file a COS study using the summer peak allocation method with its next Phase II electric rate case.

C. Treatment of SCS-6 and SCS-7 Customers

35. The Company has two Special Contract Service (SCS) customers—the Denver Water Board (SCS-6) and the RTD Light Rail system (SCS-7). According to Public Service, each of these customers has certain unique characteristics that justify each receiving special contract service. Under the Company's proposal, production and delivery loads for these customers would be treated separately for pricing and billing purposes and, as such, would not affect the allocation of costs to these loads.

36. Public Service proposes to continue to charge Denver Water Board its share of the production costs based on a Real-Time Pricing structure, and to charge them for the associated delivery of the power at the same rate as rest of the Commercial and Industrial (C&I) customers.

37. As for the RTD Light Rail system, the Company notes that due to the mobile nature of the load, the system requires additional delivery capacity relative to the capacity needed at the generation level. Consequently, Public Service proposes that the production capacity charge should apply to the simultaneous maximum demand of the total RTD Light Rail load, while the delivery capacity charges should apply to the maximum measured demand at each Traction Power Station[11] at the production and delivery charges applicable to all Primary

[11] We note that Public Service did not propose to change the Schedule SCS-7 Sheet No. 77A in its tariffs. Sheet No. 77A specifies how demand will be determined for billing purposes. Public Service's proposal to use different parameters for measuring the billing demands for production and delivery charge purposes requires modification of the Sheet No. 77A section: Determination of Billing Demand.

General (**PG**) customers. Under the Company's proposal, the delivery charge of $3.94/kW-Month would be applicable for all other **PG** customers as well as these two SCS customers.

38. On the other hand, Staff disagrees with this approach and proposes separate customer classes for these two customers. Under Staff's separate class approach, it calculates a delivery charge for SCS-6 of $2.65/kW-Month, a delivery charge for SCS-7 of $2.05/kW-Month, while all other **PG** customers would incur a delivery charge of $3.60/kW-Month.

39. After consideration of the offered proposals, we adopt Public Service's proposal for the treatment of Denver Water, SCS-6 and the RTD light rail system, SCS-7. We are persuaded by the Company's argument from a "cost causer" standpoint that Denver Water and the RTD light rail system are no different than other **PG** customers. Therefore, Public Service shall include SCS-7 as part of the **PG** rate class for cost allocation purposes of system production and delivery charges and shall include SCS-6 as part of the **PG** rate class for cost allocation purposes of system delivery charges. Public Service shall account for these customers' unique circumstances through the pricing and billing process. In making this ruling, the Commission notes that Public Service will need to modify the tariff for Schedule SCS-7, Sheet No. 77A (Determination of Billing Demand) section to reflect our decision to allow different parameters to be used for measuring the production and delivery demands for billing purposes.

D. Treatment of Section 40-3-104.3 Customers

40. Section 40-3-104.3, C.R.S., provides that Public Service may charge a specific customer or potential customer by contract without reference to its tariff, provided certain conditions (spelled out in the statute) are met. The controversy in this case centers upon the interpretation of § 40-3-104.3(2)(a), C.R.S., which reads in part:

> …at the time of any proceeding in which a utility's overall rate levels are determined, the commission shall specify a fully distributed cost methodology to

> be used to segregate rate base, expenses, and revenues associated with utility service provided by contract pursuant to this section from other regulated utility operations.

41. This Phase II case is the first proceeding since the passage of the statute in which the Commission will establish the methodology to segregate rate base, expenses, and revenues associated with these customer contracts for Public Service.

42. Public Service believes that, to comply with the provisions of § 40-3-104.3, C.R.S., it is necessary to adjust its rate revenue account so that it reflects what would have actually been billed to these contract customers under standard tariffs. The Company then assumes it must credit Account No. 451 with the amount of the discount to eliminate the bill reductions from the account. According to Mr. Keyser, this produces the cost structure that would have existed had the contract customers been served under tariff rates rather than the contracts rates. He suggests that whatever method is ultimately selected for segregating ratebase, expenses, and revenues, it should be as consistent as possible with the method used to determine the revenue level to be paid by each individual customer.

43. Staff witness Ms. Fischhaber argues that Public Service's method does not comply with statutory requirements for segregating ratebase, expenses, and revenues. She maintains that, to comply with § 40-3-104.3(2)(a), C.R.S., the customer contracts need to be considered as separate rate classes. According to Staff, it used the contract customer specific data to segregate the contract customer data from the data for the other general rate classes. Once the contract customer data was segregated from the general rate classes, new sums of individual maximum demands by class, class NCP, class contributions to CP, and class energy usage were calculated for the general rate classes.

44. Mr. Keyser contends, on page 13 of his Rebuttal testimony, that Staff's separation of these customers into additional classes for cost allocation purposes produces a total revenue requirement that is different from the total revenue that would result if these customers paid the full tariff rate. He contends that Staff's method results in an increase in costs for other customers which violates the intent of the statute that other ratepayers not be affected by the discounts. Mr. Keyser also argues that Staff's method "bakes into" the full tariff rate a credit reflecting the level of cost assigned to the discounted customer. He maintains this baked-in result would discourage Public Service from entering into some discounted sale contracts which would be contrary to the intent of the General Assembly in enacting this statute.

45. We adopt Public Service's proposed treatment of § 40-3-104.3, C.R.S., customers. We find that Public Service's proposal allocates costs to these customers the same as if they did not qualify for § 40-3-104.3, C.R.S., discounts. Staff's proposal to separate these customers out into their own rate classes would not meet the intent of the statute because it would impact the amount of costs allocated to the other remaining customers. We note that, to qualify as a § 40-3-104.3, C.R.S., customer, these entities must express their intention to decline, discontinue, partially discontinue, or provide their own service. Such discontinuance of service could have a negative effect because the remaining customers would pay more to cover the associated fixed costs that the § 40-3-104.3, C.R.S., customers currently pay.

E. Treatment of the Boulder IBM Plant Customer

46. Within his Answer testimony, Mr. Wendling represents that there is now a dedicated 230kV buried transmission line serving the Boulder IBM plant (IBM). He contends that this line results in a level of reliability not normally enjoyed by other primary voltage

customers, since the IBM plant has two dedicated sources of power. Consequently, he recommends a separate customer-specific S&F charge for IBM.

47. While Mr. Darnell agrees with Mr. Wendling that IBM is receiving a higher level of reliability, he states that IBM pays for this increased reliability through an excess facilities charge. He responds in his Rebuttal testimony that Staff's recommendation would unfairly penalize IBM by requiring it to pay both a S&F charge for "dedicated" facilities as well as a primary delivery level demand charge. He explains that these facilities act as a looped system. According to Mr. Darnell, there have been several instances when, for emergency or maintenance reasons, customers other than IBM have been served with these looped facilities.

48. During the hearing, Public Service witness Mr. Niemi stated that IBM paid a one-time non-refundable payment of $158,500 for reserve capacity. He further stated that IBM makes a monthly payment of $1,580 for the reserve capacity. According to Mr. Niemi, this monthly payment includes the excess facilities charge for IBM.[12]

49. In a footnote in its Statement of Position, Staff maintained that it is concerned that this excess facility charge was not set forth anywhere in Public Service's tariffs. Staff pointed out that the setting of rates by non-tariff contract is possibly a violation of Public Utilities Law and Commission Rule 4 CCR 723-1-40. However, we point out that Public Service's Colo. PUC No. 7 Electric tariff at Sheet No. R123 expressly provides for excess facilities charges.

50. That portion of the tariff states: "[I]n those instances where [Public Service] provides distribution facilities at Customer's request in excess of the facilities necessary to

[12] *See* Volume 5, January 21, 2005, transcript page 128, line10, through page 130, line 13.

supply service to Customer, Customer shall be required to contract to pay Company for such facilities ….” Given the express language in this tariff, we find Staff’s argument unavailing.

51. We adopt Public Service’s proposal for treatment of the IBM Boulder plant. Public Service’s testimony indicates that IBM is paying for excess facilities and therefore it is covering the costs of the delivery system. We find no need for IBM to pay a S&F charge to recover costs associated with these dedicated facilities. The record contains no evidence that IBM is being subsidized.

F. Treatment of SG, PG, and TG Rate Classes for Allocation Purposes

52. The Company has proposed to treat the C&I customers (**SG**, **PG**, and **TG**) as a single rate class for cost allocation purposes because the customer’s choice of delivery level voltage does not affect the cost of providing that customer with production and transmission capacity. Public Service indicates that it factors losses into its rate design for **SG** and **PG** customers to reflect the cost difference in delivery levels.

53. On page 21 of his Answer testimony, Mr. Wendling contends that the Company’s proposal “mashed” together the costs for capacity and delivery charges for the **SG**, **PG**, and **TG** classes and, in doing so, developed a rate design which will ensure that one class will be subsidizing another. Staff contends that, to correct this error, it preserved the class cost distinctions and developed rates which reflect the individual class cost responsibility and billing units.

54. However, according to Public Service witness Mr. Keyser, while Staff dismisses the Company’s proposal as “an error,” Staff’s method produces anomalous results which Public Service sought to avoid. In his Exhibit RAK-10, Mr. Keyser converts the respective summer and

winter demand charges for **SG** and **PG** to transmission level by accounting for line losses for both the Company's case and the Staff's case. When this is done, the Company's summer and winter demand charges are the same between the three sets of customers (**SG**, **PG**, **TG**) while Staff's summer and winter demand charges vary between these three sets of customers.

55. The graphs in Company witness Mr. Darnell's Direct testimony reflect that the **PG** and **TG** customers have relatively flat lines of growth between the years 1996 and 2002 and that their summer and winter peaks are very close. However, the graph for the **SG** class shows that growth is increasing for summer months while at the same time its winter growth remains flat. Thus, we conclude that this results in a divergence between their summer and winter peak loads.[13] The record reveals that the **SG** class has 34,650 customers, the **PG** class has 605 customers, and the **TG** class has 24 customers.[14]

56. We reject both Public Service's proposal and Staff's proposal for treatment of the **SG**, **PG**, and **TG** rate classes. Instead, Public Service shall treat the **SG** customers as a separate rate class and shall collapse the **PG** and **TG** customers together for cost allocation purposes. Our decision is based on the evidence in the record that indicates that the **PG** and **TG** customers place similar demands on Public Service's system. The record further establishes that the number of **SG** customers warrants a separate rate class.

G. Treatment of the R and RD Rate Classes for Allocation Purposes

57. The Company proposes to include the Residential Demand (**RD**) customers as part of the **R** class for cost allocation purposes. In contrast, Staff proposes to have two

[13] *See* Hearing Exhibit 1, pages 14 and 15.
[14] *See* Hearing Exhibit 11 Exhibit RAK-2, page 21 of 25.

residential classes: one with demand meters (**RD)**, and one without (**R)**, for cost allocation purposes.

58. Company witness Mr. Keyser disagrees with Staff's separation of the residential class into two classes, **R** and **RD**. He contends that Staff's proposal is not justified by either the nature of the service provided or the load characteristics of the customers. He argues that Staff's proposal ignores the fact that the cost Public Service incurs to serve these customers and the service they receive is exactly the same. The Company simply has the option of two different rate structures. In his opinion, Staff's proposal will produce inconsistent and conflicting price signals. According to Mr. Keyser, the **R** class has a summer/winter price differential while the **RD** class has no summer/winter differential at all.

59. At the hearing, Staff witness Mr. Wendling testified that the **RD** customers have a winter peak demand that is over two and one-half times their summer peak demand.[15] The exhibits to Mr. Wendling's answer testimony substantiate that the **RD** customers have a much higher winter to summer peak than the **R** customers, which have similar winter and summer peaks.[16]

60. Based on the evidence and testimony presented, we adopt Staff's proposal to treat **R** and **RD** customers as separate rate classes for cost allocation purposes. Commissioner Miller dissents on this point and argues that the two customer classes should be treated as one class without further comment.

[15] *See* Volume 8 January 26, 2005 transcript page 14 lines 17 through 22.
[16] *See* Hearing Exhibit 63, WLW-4, Schedule 7 pages 2 and 3 CORRECTED JANUARY 3, 2005.

H. The Secondary Distribution Cost Allocator

61. Public Service has proposed to create a new allocation factor for its investments in Secondary Distribution facilities, which it called a Secondary NCP method. Mr. Keyser contends that an allocation factor based on the sum of individual customer's annual maximum demand would be too severe, while on the other hand, an allocation factor based on a straight NCP method would reflect a level of diversity that is much greater than the level experienced at the secondary voltage level. As a middle ground, he proposed an allocation factor that is weighted by the total NCP and individual maximum demand values. Mathematically, this allocation factor is derived by taking the average of the NCP demands and the sum of individual maximum demands.

62. Staff developed a modified version of the Company's proposed Secondary NCP method, which weights on an equal basis (50/50) the individual maximum demand and the NCP of the class. Mr. Wendling contends that Public Service's new allocation factor fails to consider the high load diversity that small customers, such as residential customers, display. To address this problem, Staff equally weights the individual maximum demand and the NCP of the class. Mathematically, Staff first determines the separate NCP and individual maximum allocators and then averages the resulting allocators.

63. According to Mr. Keyser, although these two methods produce an allocator which is very similar in terms of inputs, the results are quite different. He calculates that employing Staff's allocator would shift about $5 million of revenue requirement from the **R** class to the **SG** customers within the C&I class. By his calculations, this would equate to an additional decrease to the **R** customer of about 1.1 percent while at the same time placing an additional increase on the **SG** customer of about 1.2 percent. The Company has proposed a rate decrease for **R**

customers of 1.36 percent and a rate increase for its **SG** customers of 1.75 percent.[17] If the Commission were to adopt Staff's method it would only widen the gap between the two, according to Mr. Keyser.

64. Finally, Mr. Keyser contends that the Company's allocator attempts to recognize the fact that secondary distribution facilities must be sized to meet the expected maximum demand, and that secondary load diversity can vary greatly among classes of service.

65. In examining Mr. Keyser's Exhibit RAK-3, page 3 of 25, the **R** class has a Sum of Individual Maximum Demand of 7,846,936 kW and a Class Maximum Demand of 1,843,797 kW. Dividing the Sum of the Individual Maximum Demand by the Class Maximum Demand results in a ratio of 3.26 for the **R** class. Performing this same ratio calculation for the other rate classes shown on that exhibit, the **SG** class has a ratio of 0.43. This demonstrates to us that the **R** class has a high level of diversity that is beneficial to all customers. In other words, if the Company had to install facilities to meet the **R** class's Sum of Individual Maximum demands, it would need significantly more facilities.

66. Therefore, we adopt Staff's proposed secondary distribution allocator. We find that this allocator recognizes that the **R** class has much more diversity than the other rate classes, because **R** class customers require fewer distribution facilities to meet their load requirements than other customer classes served by the distribution system.

I. Distribution Substation Treatment

67. Consistent with the position it took in the Phase I portion of this proceeding, Public Service reclassified certain high-voltage facilities which were previously booked as distribution plant and included them as transmission plant. The Company's rationale for the

[17] *See* Hearing Exhibit 93, Revised RND-1.

reclassification was to ensure a match between those capital assets classified as transmission and the facilities that would be turned over for operation by a Regional Transmission Organization (RTO). According to Public Service, leaving the high side facilities in the distribution substation function results in distribution delivery level retail customers subsidizing transmission delivery level and wholesale customers, as well as third-party users of the transmission system who are taking service under the Company's Federal Energy Regulatory Commission (FERC) jurisdictional Open Access Transmission Tariff (OATT).

68. Staff disagrees with the reclassification because the historical rationale for classifying substation facilities as either transmission or distribution depended on the use of the substation. According to Staff, the plant in question would not have been constructed if Public Service had not constructed the substation for the purpose of serving customers at distribution voltage levels.

69. In his Rebuttal testimony, Mr. Keyser contends that the "but for" argument raised by Staff is nothing more than a red herring. According to Mr. Keyser, customers do exist and the transmission system exists to transmit power to all substations. He contends that these "high-side" facilities function as an integral part of the transmission system and should therefore be functionalized as part of the integrated transmission system. Mr. Keyser notes that, in the jurisdictional allocation process, distribution substation assets are allocated 99.84 percent to the Colorado retail jurisdiction, while integrated transmission system assets are allocated 79.56 percent to Colorado retail jurisdiction. According to Mr. Keyser, the advantage of

adopting the Company's method is a reduction in the revenue requirement of $505,013 per year to the retail customers of Public Service.[18]

70. At the hearing, Mr. Keyser produced a drawing on the Commission's white board demonstrating the type of facilities the Company proposed to reclassify. He also explained how the electricity would flow if a wholesale customer sought to purchase transmission service between two points.[19] In his drawing, Mr. Keyser provided two possible substation configurations: an in/out substation, and a directly connected substation. Under the Company's proposal, only the high-side of the in/out substation configuration would be classified as part of the transmission system. This is because, in Mr. Keyser's opinion, a wholesale customer should have to pay for a portion of those high-side facilities since the flow of electricity would pass through them in a point-to-point wholesale purchase.

71. We agree with Public Service's reasoning on this point. We therefore adopt Public Service's proposal to treat the high-side of distribution substations as transmission facilities. Public Service's testimony persuades us that this treatment is more equitable to retail ratepayers.

J. Radial Line Treatment

72. Consistent with the position it took in the Phase I portion of this proceeding, Public Service reclassified certain radial transmission lines as central transmission system which were previously directly assigned to the rate class served by the radial transmission line. The Company's rationale for the reclassification was to ensure a match between those capital assets classified as transmission and the facilities that will be turned over for operation by a RTO.

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[18] This figure was the maximum impact value agreed to by the parties in the Phase I Settlement. *See* page 48 of the agreement.

[19] *See* Hearing Exhibit 85.

73. Public Service contends that FERC requires radial transmission lines to be "rolled-up" into central transmission system because it is always possible for these lines to be looped back into the grid, making them an integrated part of the transmission system. Mr. Keyser, in his Phase I Rebuttal testimony, stated that the two advantages of maximizing the portion of the electric system's assets considered as transmission assets are: 1) the retail customers' responsibility is reduced because more is allocated to FERC; and 2) Colorado consumers could end up paying twice for transmission type assets in a RTO setting.

74. Staff witness Ms. Fischhaber disagreed with the Company's proposed roll up of radial transmission lines into the central transmission system. She believes radial lines should be directly assigned to those customers being served by those lines as Public Service has historically done. She reasons that if radial lines are rolled-up into the total transmission system, the general body of ratepayers are paying for parts of the system that are of no benefit to them, while customers that solely benefit from the radial transmission line do not pay the appropriate cost for their exclusive use of that radial transmission line. In her opinion, the argument that radial lines could eventually be looped into the integrated system should not be the basis for rolling them into part of the transmission system.

75. Ms. Fischhaber responds to Mr. Keyser's first stated advantage in his Phase I Rebuttal testimony by arguing that, while it may be true that fewer costs will be allocated directly to Colorado retail customers up front, these costs will eventually be allocated to Colorado retail customers through FERC tariffed transmission rates if Public Service becomes a member of a RTO. As for the second stated advantage, she concedes that there may be some merit to this argument. Nonetheless, she believes it is premature for the Company to begin

classifying plant at this time. She recommends a wait-and-see approach until Public Service commits to joining a RTO.

76. Mr. Keyser responds that, although Ms. Fischhaber concludes that the general body of ratepayers will be harmed by rolling in these radial lines, she ignores the reality of the total system costs. There is approximately $10.0 million of investment in radial lines and Staff only allocates about 8 percent to FERC. Under the Company's approach, 21.46 percent is allocated to FERC. Mr. Keyser concludes that, if Staff's method is adopted, it would result in a $159,070 increase in the Colorado retail base rate revenue requirement.[20]

77. Climax witness Mr. Baron argued that the Company's treatment in this case is consistent with its proposed treatment in its pending OATT proceeding at the FERC. Under the FERC proceeding, wholesale customers would pay for these radial lines. He also contends that, if the Commission were to adopt Staff's method, the Company could be in the position to double-recover some of these costs.

78. After considering the arguments advanced here, we adopt Public Service's proposal to treat radial transmission lines as general system transmission. Although all parties presented well considered arguments regarding this issue, we find that the more prudent course is to accept the Company's proposal in order to prevent an over-recovery, which we find to be inherent in Staff's proposal.

K. Service and Facility Charges for the R and C Rate Classes

79. At the hearing, OCC witness Dr. Stutz provided his analysis of how people moderate their consumption only if the moderation affects their bill. In terms of rate design

[20] This figure was the maximum impact value agreed to by the parties in the Phase I Settlement. *See* page 48 of the agreement.

criteria, he pointed out that there are tradeoffs between the portion of equity that reflects collecting costs from the people who cause them, and the efficiency that asks people to consume energy efficiently. Dr. Stutz testified that his proposal to reduce the S&F charge from $6.25 to $5.00 for both **R** and **C** classes is to make a very modest move in the direction of rates which are more responsive to customer efficiency. Under his proposal, the reduction in S&F charges would create a $15.45 million shortfall for Public Service. Dr. Stutz proposes to offset this shortfall by raising the kWh rate for the seasonal differential from 1.0 cents to 1.043 cents.

80. In his Rebuttal testimony, Company witness Mr. Darnell disagrees with Dr. Stutz's proposal to reduce the S&F charge for **R** and **C** classes to $5.00 because, in his opinion, it is poor pricing practice. He maintains that the Company would under-recover the fixed costs that should have been recovered in the S&F charge if Dr. Stutz's proposal is adopted.

81. We reject the OCC's proposal to set the S&F charge for the **R** and **C** rate classes at $5.00. We find that to set the S&F charge at $5.00 would diverge from cost based rates and would result in higher use customers subsidizing lower use customers.[21]

L. Allocation of Customer Accounting Expenses to the Lighting Classes, Interconnection Service, and Transformer Rental Service

82. Public Service did not allocate any Customer Accounting costs to the Lighting classes, Interconnection service, or the Transformer Rental service.

83. In contrast, Staff allocated Customer Accounting costs to all classes and services including Lighting, Interconnection, and Transformer Rental because it believes that some form of revenue accounting takes place. Staff proposed a minimum allocator of 0.01 percent.

[21] For example, single home customers would probably end up subsidizing vacation home customers, a result we find untenable.

84. Mr. Keyser contends that it's improper to allocate Customer Accounting costs for Interconnection and Transformer Rental services since the S&F charges these customers already pay for electric service capture the appropriate amount of Customer Accounting costs. As for the Lighting classes, he asserts that the vast majority of monthly lighting bills are for residential and commercial area lights and the unincorporated area streetlights. Mr. Keyser states that these lighting bills are included as a separate item on the customer's normal monthly bill for electric service. As for the lighting services related to streets and highways, in which stand alone monthly bills are issued to the various cities and state agencies, there would be a minimal amount of Customer Accounting costs, but he considers it negligible.

85. We are not convinced by Staff's proposal to allocate costs for customer accounting expenses. In doing so we accept Public Service's proposed treatment. We find that it is not worthwhile to allocate the small amount of customer accounting expense to the Lighting classes, Interconnection service, and Transformer Rental service. In addition, Staff's proposed allocator is not based on how the Company actually incurs Customer Accounting costs.

M. Rate Design for SG and PG Customers (Elimination of Demand Ratchets)

86. Within his Answer testimony, Staff witness Dr. Shiao stated that he does not oppose the Company's proposed elimination of the 75 percent minimum demand requirement, but is concerned that Public Service may not recover all of the fixed costs of facilities associated with customers who are subject to the demand ratchet. He noted the similarities between the Company's proposed Standby and Supplemental services for customers that have their own generation, and customers who are subject to the demand ratchet. As an alternative, he suggests that Public Service could require **SG** and **PG** customers, which are currently subject to the

demand ratchet, to pay the Standby and Supplemental Service charge to recover the fixed capacity costs of the delivery system.

87. BOMA witness Mr. Binz stated in his Cross-Answer testimony that BOMA takes no position on Staff's suggestion that the Standby and Supplemental Service charge be used instead of a demand ratchet, but would like Staff to provide more details.

88. We reject Staff's proposal to replace the demand ratchet with the Standby and Supplemental Service charge. As parties pointed out, this proposal was not developed fully enough for us to determine how customers would be impacted.

N. Rate Design for SGL Customers

89. Staff witness Mr. Dominguez raised a concern in his Answer testimony regarding the proposed Secondary General Low Load Factor (**SGL**) rate. He believes that the Company's proposed **SGL** rate is improperly designed and may result in a situation in which Public Service does not recover the delivery costs in months when the **SGL** customer does not take service. In order to address this problem, Mr. Dominguez recommends that a **SGL** customer be billed based on its highest monthly demand from the previous 12 months. During cross-examination, Mr. Dominguez stated that he had not prepared an analysis on the possible impact on an **SGL** customer if his proposal was adopted, and had not prepared any draft tariff language regarding his proposal,

90. We decline to adopt Staff's proposal to bill **SGL** customers for the highest of the customer's monthly demand for the previous 12 months. We do not believe this proposal was developed enough for us to determine whether it should be implemented. We also note that adoption of Mr. Dominguez's proposal would have the effect of putting in a *de-facto* demand

ratchet for SGL customers, which would be inconsistent with our previous ruling on demand ratchets.

O. Downtown Denver Special Study

91. Mr. Wendling alleges that the Downtown Denver primary network provides two independent primary sources of power to each building. He contends it is unclear whether the dense downtown load provides sufficient revenues to support the level of investment the Company has made. As a result, he recommends the Commission order Public Service to conduct a study of the downtown Denver network and file the results with its next rate setting filing.

92. Mr. Darnell responds in his Rebuttal testimony that the Commission should open a docket to investigate this issue if it so chooses.

93. We decline to adopt Staff's proposal for a Downtown Denver Special Study. There is no information in this record that indicates how such a study would be conducted. For example, how would the Downtown Denver area be defined? It also raises the question as to whether a similar study should be conducted on other high-value commerce areas such as the Denver Technological Center or Denver International Airport.

IV. SETTLEMENT AGREEMENTS

A. Settlement Agreement Resolving Issues on Interruptible Electric Service

94. On January 19, 2005, Public Service joined by Staff, CEC, FEA, the OCC, and CF&I (collectively ISOC Parties) filed a Motion to Approve Settlement Agreement Resolving Issues on Interruptible Electric Service (ISOC Motion) along with the Settlement Agreement

Resolving Issues On Interruptible Electric Service (ISOC Settlement). The ISOC Settlement resolves issues raised regarding Public Service's proposed ISOC tariff. ISOC Parties agreed to:

- provisions for three types of interruptions: Capacity, Contingency, and Economic (including buy-through);
- a formula to determine Contract Interruptible Load;
- a process to seek relief if Contract Interruptible Load is not representative for a year;
- a formula to determine Avoided Energy Cost;
- cost recovery of actual credits paid through DSMCA;
- monitoring and reporting requirements; and
- a specific ISOC tariff (Exhibit A to the ISOC Settlement).

95. Public Service proposed a new ISOC tariff to replace its existing interruptible tariffs. No party took issue with Public Service's contention that the existing interruptible tariffs do not provide appropriate incentives for Public Service operators to call interruptions, or for interruptible customers to agree to Economic Interruptions. However, Staff, the OCC, CEC, FEA, and CF&I raised several issues regarding specific definitions, formulas, and provisions of the proposed ISOC tariff. On Rebuttal testimony, Public Service agreed with some of the parties' recommendations to modify: 1) the formulas to determine Contract Interruptible Load, Capacity Availability, and Avoided Energy Cost; 2) the definition of Interruptible Demand; 3) provisions for Failure to Interrupt and buy-through of Economic Interruptions; and 4) the availability criteria. Public Service incorporated these agreements into the proposed ISOC tariff provided with its Rebuttal testimony. Based on the cross-answer testimonies of the parties it was likely that some of the modifications agreed to by Public Service to address the concerns of one party created new issues for other parties.

96. The ISOC parties reached comprehensive agreement for all issues raised regarding the proposed ISOC tariff. This ISOC Settlement was problematic in that it contained provisions that were not identified in any written testimony. During the hearing on the ISOC Settlement, Public Service witness Mr. Sheesley provided information on these "new" provisions and indicated that these provisions arose in settlement discussions to address concerns that also surfaced during settlement discussions. Mr. Sheesley also clarified several of the ISOC tariff provisions including:

- interruptible customers with standing buy-through orders must call the Company within the 15-minute notice period to advise the Company that the customer desires to be interrupted;[22]
- the 15-minute notice period begins when the Company sends the initial interruption notification e-mail to customers;[23]
- interruptible customers requesting to be interrupted after initially opting to buy-through will be interrupted for the remainder of the interruption period;[24]
- Public Service's disturbance control standard criteria is a portion of the North American Electric Reliability Council (NERC) Policy 1, Generation Control and Performance;[25]
- Public Service will use the same unit optimization model for the cost/benefit analysis that it used to determine the daily market positions;[26]
- existing interruptible customers will be required to sign an Interruptible Service Option Agreement prior to being placed on the ISOC tariff;[27]
- physical control means that the Company will have the direct control of the interruption signal device and switching equipment for a customer receiving service under the less-than-10-minute notice provision of the ISOC tariff;[28]

[22] *See* Volume 10, January 27, 2005, transcript page 227, lines 16 through 21.
[23] *See* Volume 10, January 27, 2005, transcript page 244, lines 5 through 11.
[24] *See* Volume 10, January 27, 2005, transcript page 227, line 22 through page 228, line 8.
[25] *See* Volume 10, January 27, 2005, transcript page 231, line 1 through page 232, line 17.
[26] *See* Volume 10, January 27, 2005, transcript page 233, lines 15 through 20.
[27] *See* Volume 10, January 27, 2005, transcript page 235, lines 20 through 24.
[28] *See* Volume 10, January 27, 2005, transcript page 236, line 18 through page 237, line 11.

- June through September of 2004 data will be used to determine the Contract Interruptible Load that will be used for the remainder of 2005;[29] and
- interruptible customers must cancel service under the ISOC tariff by written notice (an e-mail does not constitute written notice).[30]

97. During the hearing, a minor revision was made to the ISOC tariff attached to the ISOC Settlement to delete the words "less than" before "one hour" and "eight hours" in the Advance Notice portion of the Notice Factor definition. The ISOC Parties agreed with this change.

98. The other Phase II parties that did not enter into the ISOC Settlement have not indicated opposition to it. The ISOC Motion indicates that Climax neither joins in, nor opposes the ISOC Settlement.

99. We find it in the public interest to grant the ISOC Motion by approving the ISOC Settlement as offered including the minor revision to the ISOC tariff made during the hearing. We clarify that June through September of 2004 shall be used to determine the Contract Interruptible Load that will be used for the remainder of 2005.

100. We encourage Public Service to submit an application addressing cost recovery of interruptible credits when actual interruptible credits exceed 1 percent of base rates. ISOC Parties were unable to identify the amount of interruptible credits because of the uncertainty of customer response to the new ISOC tariff. Therefore, we find it prudent to allow cost recovery of interruptible credits through the Demand Side Management Cost Adjustment (DSMCA) for administrative efficiency. Nonetheless, the DSMCA mechanism was approved to recover the costs associated with Demand Side Management (DSM) programs. As such, we do

[29] *See* Volume 10, January 27, 2005, transcript page 237, line 19 through page 238, line 1.
[30] *See* Volume 10, January 27, 2005, transcript page 241, lines 3 through 8.

not consider the interruptible credits provided for by the ISOC tariff to be a DSM program.[31] The Commission should reconsider cost recovery of interruptible credits when the amount exceeds 1 percent of base rates.

101. We further encourage modifications outside of a rate case if results of a cost/benefit analysis indicate that the ISOC tariff is not beneficial. Mr. Sheesley testified that, indeed, the ISOC tariff could be modified outside of a Phase II rate case proceeding.[32] Given that ratepayers did not receive appropriate benefits from the discounts provided to interruptible customers under the current tariffs, we strongly encourage Public Service not to wait until another Phase II electric rate case to propose changes to the interruptible tariff if ratepayers are not receiving appropriate benefits.

B. Windsource Settlement Agreement

102. On January 14, 2005, Public Service, Staff, WRA, and Boulder (collectively Windsource Parties) filed a Motion to Approve the Windsource Settlement Agreement (Windsource Motion) along with the Settlement Agreement (Windsource Settlement), to resolve issues related to Public Service's proposed Windsource rates. The primary issue resolved is the agreement from Public Service that it will continue its previous pricing for Windsource rates. Windsource is Public Service's optional program whereby electric customers can pay an additional fee for wind-generated energy.

103. When Public Service first began the Windsource program, the Commission approved the incremental cost for Windsource power at $2.50 for each hundred kWh block. This

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[31] Mr. Sheesley testified that the interruptible credits and their associated MW quantities will not count as part of the $196 million (2005 dollars) for DSM programs, or the 320 MW of DSM agreed to in the LCP settlement. *See* Volume 10, January 27, 2005, transcript page 232, line 18 through page 233, line 3.

[32] *See* Volume 10 January 27, 2005 transcript page 234 lines 2 through 9.

rate was established based on "value pricing," and was not a cost-based rate. That is, the rate was a result of negotiations by intervening parties. At that time a portion of energy costs were included in base rates. Public Service's proposal in this case to remove purchased energy and fuel costs from base rates requires Windsource rates to be adjusted accordingly. Public Service also proposed to increase Windsource rates. Several parties objected to this increase, arguing that costs for wind generated power have been decreasing over time. In the Windsource Settlement the parties state that they were unable to agree on a cost-based rate approach, but agreed to continue the current rates that were established through the "value pricing" approach from a negotiated settlement.

104. As established in the Windsource Settlement, Windsource rates will remain at the same cost of $0.01287 per kWh for base rates plus $0.025 per kWh[33] for the Windsource premium, or $0.03787 per kWh at secondary voltage. The rate is $0.03761 per kWh at primary voltage and $0.03733 per kWh at transmission voltage. The Windsource Parties also agree to credit the Air Quality Improvement Rider (AQIR), ECA, and Incentive Cost Adjustments, as detailed in Exhibit A to the Windsource Settlement.

105. In the Windsource Settlement Public Service also agrees to obtain Green-e certification for its Windsource program from the Center for Resource Solutions (CRS). During the hearing on the Windsource Settlement, Public Service witness Mr. Sulkko provided information about Green-e certification through CRS. Mr. Sulkko explained that CRS is a non-profit organization that endorses environmentally preferred energy products if they meet certain audit requirements for their supply sources, and if marketing information complies with their

[33] $2.50 per 100 kWh block.

code of conduct.[34] Mr. Sulkko indicated that he believes Public Service's program currently meets the CRS certification requirements.

106. According to the Windsource Settlement, the Company must submit its application for Green-e certification by May 1, 2005. Public Service must additionally take all reasonable steps to correct any deficiencies, at shareholder expense.[35] Any deficiencies identified that would be applicable to sales made on or after August 1, 2001, must also be corrected. Mr. Sulkko represented that, if modifications are necessary the Company could purchase additional wind energy, or renewable energy credits. In response to questions about the requirement that the certification review extend back to August 1, 2001, Mr. Sulkko stated that Windsource Parties raised concerns about the Ridgecrest Power Purchase Contract for wind energy that Public Service entered into on that date. Some of the Windsource Parties argued that language in this contract is vague or ambiguous and raised concerns about wind energy supplies for the Windsource program. The Green-e certification would include a review by CRS of this contract, consequently the Windsource Parties agreed to begin the review period on August 1, 2001. Mr. Sulkko indicated that, if problems were found in a prior period, Public Service could purchase either historic or current renewable energy credits to offset a prior deficit.

107. We find it in the public interest to grant the Windsource Motion by approving the Windsource Settlement. Public Service's clarification that any costs to obtain Green-e certification will be borne by the shareholders alleviates any concerns we have about the Windsource Settlement. However, we further clarify that other ratepayers shall in no way be negatively impacted by continuation of value pricing and obtaining Green-e certification for the

[34] *See* Volume 10 January 27, 2005 transcript page 194 line 3 through page 195 line 8.
[35] *See* Volume 10 January 27, 2005 transcript page 204 lines 3 through 11.

Windsource program. Although we prefer cost-based rates, we agree that it is reasonable to continue the value pricing approach in the absence of a cost-based analysis. Nevertheless, we encourage Public Service to use a cost-based approach for the Windsource rates in future rate case filings.

C. Settlement Agreement Concerning Net Metering and Net Billing Issues

108. On January 14, 2005, Public Service, Staff, WRA, the OCC, Regelson, and Boulder (Net Metering Parties) filed a Motion to Approve Settlement Agreement Concerning Net Metering and Net Billing Issues (Net Metering Motion), along with the Settlement Agreement (Net Metering Settlement). The primary issue resolved in the Net Metering Settlement is Public Service's agreement to withdraw its net metering and net billing proposals. Under the Net Metering Settlement, Public Service would then continue to use its current photovoltaic tariffs (PV Tariffs) and small power production and cogeneration facility policy tariffs (Small QF Tariffs) that apply to qualifying facilities (QFs) under Federal Public Utility Regulatory Policies Act requirements.

109. The following is a brief summary of the issues that lead to the Net Metering Settlement. Public Service proposed major changes to its net metering policies by replacing the current PV and Small QF Tariffs with its proposed Net Metering and Net Billing Tariffs. Public Service proposed significant changes to the rates and measurement of net metered customers, based on a concern that net metering provisions in the PV and Small QF Tariffs cause net metered customers to be subsidized by other customers. Several parties objected to Public Service's proposal. The parties also pointed out that Public Service did not perform the photovoltaic (PV) study required by Decision No. R98-616, Docket No. 98A-114E, and the data that was to be collected would have allowed us to determine whether net metering customers

were being subsidized by other customers. In the Net Metering Settlement, the Net Metering Parties agreed to withdraw all direct, supplement direct, answer, supplemental answer and rebuttal testimony and exhibits pertaining to net metering and net billing.

110. In the Net Metering Settlement the Parties agree to make minor modifications to the current PV Tariffs and Small QF Tariffs. Language in the current PV Tariffs that limits participation to the initial pilot program has been removed, instead opening it up to all customers with a PV system with a capacity of 10 kW or less. The Net Metering Parties also agree to limit the applicability of the Small QF Tariffs to non-PV customers. The revised tariffs reflecting these changes are proposed in Exhibit A to the Net Metering Settlement.

111. In response to the recent passage of Amendment 37, enacted as § 40-2-124, C.R.S., the Net Metering Parties agree to modify the PV Tariffs to reimburse PV customers for excess energy generated in the calendar year at the Company's average hourly incremental cost of electricity supply over the prior 12-month period. During the hearing on the Net Metering Settlement, Public Service witness Mr. Darnell explained that this average hourly incremental cost will be calculated by using the Company's Cost Calculator system to obtain the price for the last 50 MWs served in every hour, and averaging the costs over the entire year. Mr. Darnell clarified that, if the Commission's future rulemaking in response to Amendment 37 requires a different incremental cost calculation, Public Service will file tariffs as required by that ruling.[36]

112. We find it in the public interest to grant the Net Metering Motion by approving the Net Metering Settlement. We therefore agree with the approach taken in the Net Metering Settlement to maintain the existing net metering policies. We also agree that the proposed

[36] *See* Volume 10 January 27, 2005 transcript page 166 line 4 through page 168 line25.

changes to the current PV Tariffs and Small QF Tariffs, as shown in Exhibit A to the Net Metering Settlement, are reasonable. We are, however, concerned with Public Service's failure to perform the PV Study required by Decision No. R98-616. This study, had it been completed, would have provided data that would have allowed us to determine whether the existing net metering and net billing customers are being subsidized by other customers, and if they are, to what degree. We are willing to accept the rates in the existing PV Tariffs with the assumption that PV customers are not substantially subsidized by other customers. However, if a PV Study indicates subsidization is occurring the Commission has the right to revisit the rates to discontinue any subsidization.

D. PV Study

113. In 1998 Public Service applied to the Commission for approval to implement an optional pilot program whereby individual residential and commercial electric customers could purchase a rooftop PV generation system and interconnect it with the utility distribution system. Public Service and other parties in that docket filed a settlement in that case which the Commission approved.[37] In this Settlement, parties agreed that Public Service would complete such a PV Study.

114. During the hearing on the Net Metering Settlement, Public Service witness Mr. Darnell stated that it is the Company's opinion that the recent voter approval of Amendment 37 obviates the need for Public Service to complete the PV Study.[38] He opined that the purpose of the PV Study was to determine the cost/benefit of solar and to help design proper tariffs. Mr. Darnell contends that Amendment 37 provides a clearly defined goal in terms of the

[37] *See* Decision No. R98-616, Docket No. 98A-114E.

[38] *See* Volume 10 January 27, 2005 transcript page 170 line 16 through page 171 line 8 and page 175.

amount of solar generation on the Company's system, regardless of cost, though he acknowledges that the PV requirements are subject to a cost cap. He went on to argue that the PV Study was necessary to establish pricing and net metering rules for PV service, but the firm standards in Amendment 37 render this unnecessary.

115. We uphold the requirements in Decision No. R98-616 and require Public Service to complete a PV Study. We disagree with Public Service that the amount of PV generation required by Amendment 37 obviates the need for PV pricing information. Amendment 37 may require Public Service to implement certain PV and net metering provisions in order to acquire the specified amount of PV generation, but Amendment 37 does not resolve the cost and subsidization questions associated with PV generation. Though Amendment 37 requires Public Service to implement a specified level of PV generation regardless of cost, Amendment 37 limits residential customer cost exposure to $0.50 per month.[39] If PV resources cost substantially more than conventional resources, then the amount of PV resources that Public Service will be required to install will likely be limited by cost. This PV resource limit will be based on the cost difference between PV and conventional resources, which cannot be reasonably determined without the information from the PV Study.

116. Further, the Commission approved Public Service's PV pilot program with the understanding that it would produce cost/benefit information to more accurately assess the feasibility of rooftop PV systems in the future. Ratepayers have borne the cost to implement the PV program, but Public Service failed to provide one of the expected benefits of the program – information. This information would have been helpful in analyzing the costs and benefits of the

[39] It is unclear whether this limit applies to customers other than residential.

PV requirements proposed in Amendment 37. Further, the study information could allow the Amendment 37 PV requirements to be implemented in a manner that captures the maximum efficiency of customer and utility benefits. Amendment 37 does not obviate the need for the PV Study. To the contrary, we believe the implementation of the amount of PV required by Amendment 37 warrants a full implementation of the study.

117. The Commission is deeply troubled by Public Service's failure to initiate the PV Study. By blatantly ignoring a Commission Order, Public Service has done a disservice not only to this Commission, but to the general public as well. Through its failure to comply with a Commission Order, we lack the information necessary to evaluate the net metering subsidy issue in this docket. Instead, we must defer this question to a future proceeding. This results in added expense to this Commission, parties and ratepayers. Unfortunately, we do not have the statutory authority to assess these expenses against the Company. We find that Public Service's failure to complete the PV Study warrants the Commission imposing a timeline with greater accountability requirements to ensure that Public Service completes the study, and does so in a timely manner. We order Public Service to gather information necessary to complete a statistically valid study. Public Service shall address the bullet list of issues in paragraph 7 of the Settlement Agreement in Docket No. 98A-114E, at a minimum. We further require a timeline for the PV Study such that the information can be available for the implementation of the Amendment 37 requirements, to the greatest extent possible.

118. When asked to provide a timeline and the steps required to complete the PV Study, Mr. Darnell stated "…it would certainly require setting a lot of meters… Timeline, [a] couple of years, in my opinion."[40] Based on this testimony, we find it necessary to require Public

[40] *See* Volume 10, January 27, 2005, transcript page 176, lines 12 through 24.

Service to complete the PV Study in a definite timeframe. Because Public Service failed to begin the PV Study when required, there now exists a narrow window of time in which to complete the study in conjunction with Amendment 37 implementation. As required in Amendment 37, the Commission shall initiate rulemakings by April 1, 2005, and establish rules on the issues by March 31, 2006. Public Service cannot reasonably complete the PV Study within this rulemaking period, but the study results can be used to determine how much PV generation is necessary to fulfill the requirements under the $0.50 cost cap, after the rulemaking is complete. We order the following timeline:

- Within 30 days after the effective date of the Phase II decision, Public Service shall file a report with the Commission stating its written implementation plan, including the scope, design, and budget of the study.
- Within 45 days after the effective date of the Phase II decision, parties shall provide any written comment to Public Service.
- Within 60 days after the effective date of the Phase II decision, Public Service shall file a report with the Commission stating its final implementation plan.
- Within 90 days after the effective date of the Phase II decision, Public Service shall complete the installation of additional meters and other data acquisition equipment, and begin data acquisition.
- Data acquisition period shall extend for 365 days, at a minimum.
- Within 95 days after the effective date of the Phase II decision, Public Service shall file with the Commission a statement as to whether it completed the installation of the additional meters or other data acquisition equipment within the required timeframe.
- Within 18 months after the effective date of the Phase II decision, Public Service shall file a report with the Commission containing the results of the study.

E. Settlement Agreement Resolving Electric Energy Costs Issues

119. On January 31, 2005, Public Service, joined by Staff and the OCC (EEC Parties), filed a Motion to Approve Settlement Agreement Resolving Electric Energy Cost Issues along with the Settlement Agreement (EEC Settlement). The EEC Settlement resolves issues raised

with Public Service's proposal for cost recovery of all fuel and purchased energy costs through the ECA. The EEC Settlement also addresses recalculation of PCCA and DSMCA; redesign of PCCA and DSMCA mechanisms to more accurately reflect the nature of the costs that are being recovered; withdrawal of Staff's proposal for a pilot TOU ECA; and a commitment from the EEC Parties to work together to determine whether a TOU ECA should be proposed in the 2006 Phase I rate case.

120. Public Service proposed to recover all energy costs through its ECA which requires moving fuel and purchased energy (currently at $0.01287 per kWh for customers served at secondary voltage) out of base rates and into the ECA. No party took issue with this proposal. Public Service also proposed to recalculate the DSMCA and Fort St. Vrain riders to reflect that fuel and purchased energy cost were no longer recovered through base rates. Staff in its Answer testimony indicated that the PCCA would also need to be recalculated. Public Service did not acknowledge in its rebuttal case Staff's proposal to recalculate the PCCA. The EEC Parties agreed that the Company shall be permitted to recalculate the PCCA and DSMCA as proposed by the Company in its Direct Testimony and Exhibits. Notwithstanding the agreement between the EEC Parties, this EEC Settlement language poses a problem because the Company's Direct Testimony and Exhibits do not contain a recalculation of the PCCA.

121. Also during the hearing, Mr. Fanyo, attorney representing CF&I/Climax in this proceeding, raised the issue of notice of the recalculation of the PCCA, as this recalculation was not addressed in Public Service's direct case. Mr. Darnell stated that the PCCA was not addressed in the direct case because a Commission decision had not been issued on the PCCA

application when the Phase II direct case was filed. Public Service indicated that it would file the recalculated PCCA on not less than 30 days' notice to address Mr. Fanyo's concern.[41]

122. Staff in its Answer testimony also proposed that the PCCA and DSMCA riders be computed in a manner more consistent with traditional cost allocation techniques, in essence, similar to the computations of the AQIR. As a result, per kW and/or per kWh rates would be determined for these two mechanisms. Both the PCCA and DSMCA currently are computed to recover costs as a percentage of base rate revenue. The Settlement Agreement requires Public Service to file before June 1, 2005, Advice Letters with accompanying tariff sheets to redesign the PCCA and DSMCA to more accurately reflect the nature of the costs that are being recovered. Public Service proposed to eliminate existing Time-of-Day tariffs for residential, secondary, primary, and transmission customers and existing Real Time Pricing tariffs. Instead, it proposed to implement seasonal rates (discussed above), as well as modify the ECA to include mandatory TOU rates for secondary, primary and transmission voltage service levels for customers with Interval Data Recorder (IDR) metering. Public Service also proposed to lower the requirement for IDR meters from 500 kW to 300 kW. Staff, the OCC, and BOMA took issue with this proposal because of the data and the method that Public Service used to develop the TOU ECA rates. Staff advocated that a two-year pilot TOU ECA be implemented, rather than adopting permanent TOU ECA rates. Staff argued that this would allow for collection of data that could be used to evaluate whether permanent TOU ECA rates should be adopted. In its rebuttal case, Public Service withdrew its proposed TOU ECA[42] and continued to propose elimination of its existing Time-of-Day and Real Time Pricing tariffs. Public Service maintained

[41] *See* February 2, 2005, Transcript page 37, line 18 through page 39, line 4.

[42] Public Service also withdrew the requirement for customers between 300kW and 500kW to have IDR metering. *See* February 2, 2005, Transcript page 25, lines 9 through 11.

that it withdrew the proposed TOU ECA rates because the Company was hampered in its ability to demonstrate the reasonableness of its proposal because of its reliance on highly confidential information that could not be provided to parties other than Staff and the OCC. Public Service opposed Staff's proposal for a pilot TOU ECA because, according to Public Service, a pilot would only confirm that customers will act in accordance with their economic interests.

123. The EEC Parties agree that a pilot TOU ECA should not be pursued. In the alternative, the EEC Parties agree to work together over the next 12 months to determine whether a TOU ECA should be proposed in the 2006 Phase I rate case. The EEC Parties agreed to meet quarterly beginning in the second quarter of 2005. Public Service witness Mr. Darnell indicated that other parties would not be precluded from participating in these meetings. He committed that the Company would provide e-mail notification to the attorneys representing parties in this proceeding of those meetings.[43] At the EEC Settlement hearing, Mr. Darnell stated that Public Service is not opposed to adding tracking and reporting requirements to the EEC Settlement's list of issues to be discussed for a potential TOU ECA.[44]

124. The non-signatory Phase II parties have not indicated opposition to the Settlement Agreement.

125. We find it in the public interest to grant the motion by approving the EEC Settlement with certain modifications. Specifically, we: a) remove the paragraph 3 reference to recalculation of the PCCA as proposed by the Company in its Direct Testimony and Exhibits because this is not a true statement; and b) include tracking and reporting requirements to the list of issues to be discussed for a potential TOU ECA.

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[43] *See* February 2, 2005, Transcript page 13, line 21 through page 14, line 8.
[44] *See* February 2, 2005 Transcript page 26 line 7 through page 27 line 8.

126. We require Public Service to file on not less than 30 days' notice the recalculated PCCA to reflect that fuel and purchased energy will be moved out of base rates.

127. We agree with the EEC Parties that the PCCA and DSMCA should be redesigned. Ratepayers would receive more appropriate price signals if the PCCA and DSMCA costs are recovered through demand (kW) and energy (kWh) charges (instead of as a percent of base rate revenue) to more accurately reflect the type of costs that are being recovered.

128. We require Public Service to propose some type of daily time-of-use rates in its 2006 Phase I filing—*e.g.,* a proposal for a TOU ECA. The seasonal rates Public Service have proposed do not address daily time–of-use. The concerns we have about whether customers will change usage in response to the seasonal rates may be addressed by implementing time-of-day rates. We are also concerned that customers with IDR metering will pay larger service and facility fees for the metering but will no longer have the same incentive to manage their loads.

V. <u>OTHER</u>

A. Compliance

129. During the hearing, Public Service witness Mr. Niemi indicated that it would take the Company 30 to 60 days after a final order is issued to make changes in its billing system.

130. Staff in its Statement of Position requested that the Commission require an effective date on the compliance tariffs such that the tariffs would go into effect on not less than 30 days' notice. Staff contends that a minimum of 30 days is necessary to provide a reasonable opportunity for Staff, the Commission, and other interested parties to review the compliance filing.

131. Within 60 days of the effective date of this order, Public Service shall file on not less than 30 days' notice a compliance tariff filing and select a tariff effective date that allows at

least 30 days for parties to review the compliance filing. This shall be in the form of an Advice Letter with attached tariff sheets that reflect all the directives set forth in this Commission decision. We encourage Public Service to provide information to, and seek comment from, interested parties prior to making its compliance tariff filing. As part of its compliance filing, Public Service shall also submit the new summer/winter ratio as required above in Paragraph 24, along with any workpapers detailing the methodology utilized to determine the new ratio.

B. Permanent Suspension

132. The tariff sheets filed by Public Service, pursuant to Advice Letter No. 1411 - Electric as amended are permanently suspended.

C. Customer Impact

133. We require Public Service to provide the average residential (based on a usage of 625 kWh) and average commercial (based on a usage of 1,265 kWh) customer impacts.

VI. ATTACHMENTS

134. Attachment A to this order is the Settlement Agreement Resolving Issues on Interruptible Electric Service including modifications.

135. Attachment B to this order is the Windsource Settlement Agreement.

136. Attachment C to this order is the Settlement Agreement Concerning Net Metering and Net Billing Issues.

137. Attachment D to this order is the Settlement Agreement Resolving Electric Energy Costs.

VII. ORDER

A. The Commission Orders That:

1. Public Service Company of Colorado shall seasonally differentiate the production cost component of its base rates utilizing the Denver Building Owners and Managers Association's method and reflecting a summer period of the months of June, July, and August, based on the test year data consistent with the methodology developed in Denver Building Owners and Managers Association witness Mr. Binz's Exhibit RJB-4, and consistent with the discussion above.

2. Public Service Company of Colorado shall utilize the Average and Excess Demand method to allocate Production, Transmission, and Distribution substation costs consistent with the discussion above.

3. Public Service Company of Colorado shall include SCS-7 as part of the **PG** rate class for cost allocation purposes of system production and delivery charges and shall include SCS-6 as part of the **PG** rate class for cost allocation purposes of system delivery charges, consistent with the discussion above.

4. Public Service Company of Colorado shall modify its tariff for Schedule SCS-7, Sheet No. 77A – Determination of Billing Demand to reflect that production and delivery loads for this customer is treated separately for pricing and billing purposes, consistent with the discussion above.

5. Public Service Company of Colorado shall adjust its rate revenue account to reflect what would have actually been billed to § 40-3-104.3, C.R.S., customers under its standard tariffs. Public Service Company of Colorado shall also credit its Account 451 with the

amount of the discount in order to segregate rate base, expenses, and revenues associated with these customer contracts, consistent with the discussion above.

6. Public Service Company of Colorado shall continue to charge the Boulder IBM plant a monthly payment for the reserve capacity it receives, which includes the excess facilities charge for the Boulder IBM plant as set out in Public Service Company of Colorado's PUC No. 7 Electric Tariff Sheet No. R123, consistent with the discussion above.

7. Public Service Company of Colorado shall treat **SG** customers as a separate rate class and shall combine the **PG** and **TG** customers into one rate class for cost allocation purposes, consistent with the discussion above.

8. Public Service Company of Colorado shall treat the **R** and **RD** customer classes, as separate rate classes consistent with the discussion above.

9. Public Service Company of Colorado shall utilize Commission Staff's proposed Secondary Non-Coincident Peak method to determine the allocation factor for its investments in Secondary Distribution facilities, consistent with the discussion above.

10. Public Service Company of Colorado shall classify the high side of Distribution Substations as transmission facilities, consistent with the discussion above.

11. Public Service Company of Colorado shall reclassify Radial Transmission lines as General System Transmission, consistent with the discussion above.

12. The Motion to Approve Settlement Agreement regarding Interruptible Service Option Credit is granted and the Settlement Agreement is approved with minor revisions, consistent with the discussion above.

13. The Motion to Approve Settlement Agreement regarding Wind Source is granted and the Settlement Agreement is approved, consistent with the discussion above.

14. The Motion to Approve Settlement Agreement regarding Net Metering and Net Billing is granted and the Settlement Agreement is approved, consistent with the discussion above.

15. Public Service Company of Colorado shall complete a Photovoltaic study as originally ordered in Decision No. R98-616 in Docket No. 98A-114E, consistent with the discussion above. Public Service Company of Colorado shall complete a statistically valid study to specifically address the delineated list of issues identified in paragraph 7 of the Settlement Agreement in Docket No. 98A-114E at a minimum. In completing this study, Public Service Company of Colorado shall adhere to the timeline as indicated in Paragraph No. 119 above.

16. The Motion to Approve Settlement Agreement regarding Electric Energy Cost Issues is granted and the Settlement Agreement is approved, consistent with the discussion above.

17. Public Service Company of Colorado shall file on not less than 30 days' notice a recalculated Purchased Capacity Cost Adjustment, consistent with the discussion above.

18. Within 60 days of the effective date of this Order, Public Service Company of Colorado shall file, on not less than 30 days' notice, a compliance tariff and shall select a tariff effective date that allows at least 30 days for parties to review the compliance filing consistent with the discussion above.

19. Public Service Company of Colorado shall provide to the Commission the average residential and average commercial customer impacts, consistent with the discussion above.

20. Public Service Company of Colorado shall, as part of its compliance filing, provide to the Commission the new summer/winter ratio, including all workpapers detailing the methodology utilized to develop such ratio.

21. The tariff sheets filed by Public Service Company of Colorado, pursuant to Advice Letter No. 1411 - Electric as amended are permanently suspended.

22. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration shall begin on the first day following the effective date of this Order.

23. This Order is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATION MEETING March 17, 2005.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

GREGORY E. SOPKIN

POLLY PAGE

Commissioners

COMMISSIONER CARL MILLER
CONCURRING, IN PART,
DISSENTING, IN PART.

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