Decision No. C09-1446

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 09AL-299E

RE: THE TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO WITH ADVICE LETTER NO. 1535 - ELECTRIC.

ORDER ADDRESSING PHASE I AND ECA ISSUES

Mailed Date: December 24, 2009
Adopted Dates: December 1, 3, and 22, 2009

TABLE OF CONTENTS

I. BY THE COMMISSION

A. Procedural History

1. On May 1, 2009, Public Service Company of Colorado (Public Service) filed Advice Letter No. 1535-Electric. Public Service requested that the tariff pages accompanying Advice Letter No. 1535-Electric become effective on June 5, 2009. Public Service filed direct testimony in support of the rate increases proposed in the advice letter.

2. In this filing, Public Service sought approval to increase rates by $293,767,033 over existing rates, and $180,201,185 over the rates proposed in the Settlement Agreement approved in Docket No. 08S-520E.

3. The Commission has issued several orders dealing with variety of procedural issues in the course of this docket, prior to the start of the scheduled hearing. It is not necessary to reiterate each of these orders here, but we below review important milestones in this docket.

4. The Commission set proposed tariff pages for a hearing pursuant to § 40-6-111(1), C.R.S., and suspended their effective date for 120 days from the proposed effective date, through

October 3, 2009. *See* Decision No. C09-0512, mailed May 13, 2009. The proposed effective date has been further suspended until April 1, 2010. *See* Decision No. C09-1427, mailed December 18, 2009.

5. The Commission held a prehearing conference in this docket on June 18, 2009, as scheduled. *See* Decision No. C09-0709, mailed July 1, 2009. At the prehearing conference, the Commission noted interventions by right and found good cause to grant petitions to intervene by permission filed by the following entities:

- Staff of the Colorado Public Utilities Commission (Staff);
- The Colorado Office of Consumer Counsel (OCC);
- Colorado Governor's Energy Office;
- The Colorado Department of Transportation;
- Colorado Harvesting Energy Network;
- Western Resource Advocates;
- Black Hills/Colorado Electric Utility Company, L.P.;
- Interwest Energy Alliance;
- The City of Boulder;
- Boulder County Board of Commissioners;
- Energy Outreach Colorado;
- Dr. Robert A. Bardwell;
- Ms. Nancy LaPlaca (subsequently filed a Motion to Withdraw as an intervenor, which was granted in Decision No. C09-1313, mailed November 23, 2009);
- The City of Grand Junction;
- Kroger Company (Kroger);
- Wal-Mart Stores, Inc., and Sam's West, Inc. (Wal-Mart);
- Ms. Leslie Glustrom;
- Southwestern Energy Efficiency Project (SWEEP);
- Mr. Stephen Pomerance;
- The City and County of Denver;
- Ms. Alison Burchell;
- Colorado Energy Consumers (CEC);
- NAIOP, the Commercial Real Estate Development Association, Colorado Association of Home Builders, Denver Metro Building Owners and Managers Association, Forest City Stapleton, Inc., and Fitzsimons Developer, LLC; LUI Denver Broadway Office, LLC, and LUI Denver Broadway LLC (collectively NAIOP et al.);
- Cities of Arvada, Aurora, Breckenridge, Centennial, Frisco, Golden, Greeley, Greenwood Village, Lakewood, Littleton, Louisville, Superior, Thornton, Westminster, Wheat Ridge, and the Town of Poncha Springs (collectively local governments);

- Copper Mountain, Inc.,
- The Energy and Environmental Committee of the Arapahope Community Team (ACT);
- Intrawest/Winter Park Operations Corporation;
- Climax Molybdenum Company, CF&I Steel, LP, doing business as Rocky Mountain Steel Mills (Climax and CF&I);
- Colorado Solar Energy Industries Association and Solar Alliance;
- Fitzsimmons Redevelopment Authority;
- Federal Executive Agencies (FEA);
- Colorado Independent Energy Association;
- Mr. Gregg S. Eells, P.E.;
- Mr. Paul Longrigg (late filed intervention granted by Decision No. C09-0765, mailed July 16, 2009);
- Vail Summit Resorts, Inc. (late filed intervention granted by Decision No. C09-1075, mailed September 23, 2009).

6. During the prehearing conference, the Commission bifurcated the hearing in this docket into two sessions, the first one to hear Phase I revenue requirement and ECA issues and the second to hear Phase II rate design issues. The Commission also adopted a procedural schedule, scheduled a public comment hearing, and ruled on matters related to discovery. *See* Decision No. C09-0709, mailed July 1, 2009.

7. The Commission scheduled an additional prehearing conference for July 28, 2009. *See* Decision No. C09-0764, mailed July 16, 2009. During the prehearing conference held on July 28, 2009, the Commission adopted a modified procedural schedule. *See* Decision No. C09-0858, mailed August 5, 2009.

8. The evidentiary hearing on Phase I and ECA issues was held on October 26, 2009, through November 4, 2009.

9. Public Service filed the Notice of Settlement Between Public Service and Staff on November 12, 2009. By Decision No. C09-1284, mailed November 13, 2009, the Commission maintained November 16, 2009, as the deadline for all parties other than Staff and Public Service to file statements of position and for Public Service and Staff to file statements of position on the

issues not addressed in the settlement. The Commission also ordered Public Service and Staff to file the settlement on or before November 18, 2009. The Commission further ordered that the parties other than Public Service and Staff may file supplemental statements of position on the settlement between Public Service and Staff on or before November 23, 2009.

10. Pursuant to Decision No. C09-1284, the parties filed their statements of position on November 16, 2009. Public Service filed the settlement agreement on November 18, 2009, in which Staff, CEC, and EOC joined. Certain intervening parties filed supplemental statements of position on November 23, 2009.

11. The Commission held deliberation meetings on December 1, 2009, and December 3, 2009.

12. The Commission, in Decision No. C09-1283 mailed on November 13, 2009, set a procedural schedule for receiving an update about the expected in-service date of Comanche 3. On December 16, 2009, pursuant to that schedule, the Commission received an update forecasting that Comanche 3 would not be in service by December 31, 2009. As a result, the Commission issued Decision No. C09-1413, which reopened the evidentiary record for the sole purpose of addressing issues related to the status of bringing Comanche 3 online.

13. The Commission held this supplemental evidentiary hearing on December 22, 2009.

14. The Commission held a supplemental deliberation meeting on December 22, 2009.

B. The Rate Setting Process

15. Ratemaking is a legislative function. *The City and County of Denver v. Public Utilities Commission*, 129 Colo. 41, 43, 226 P.2d 1105, 1106 (1954). Ratemaking is not an exact

science. *Public Utilities Commission v. Northwest Water Corporation*, 168 Colo. 154, 173, 551 P.2d 266, 276 (1963). Rates should be "just and reasonable." *Id.* Under this standard, "it is the result reached, not the method employed, which is controlling." *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944).

16. In setting rates, the PUC must balance protecting the interest of the general public from excessive burdensome rates against the utility's right to adequate revenues and financial health. *Public Utilities Commission v. District Court*, 186 Colo. 278, 234, 527 P.2d 233, 282 (1974).

C. Adequacy of the Content of Advice Letter No. 1535-Electric and the Associated Customer Notice

17. On September 22, 2009, Wal-Mart, Sam's West, and CDOT (Movants) jointly filed a Joint Motion *in Limine*. The Joint Motion *in Limine* focuses primarily on Phase II issues, but, in the first argument presented, it raises a question concerning whether the customer notice associated with Public Service's Advice Letter No. 1535-Electric complied with § 40-3-104(1)(c)(II), C.R.S. Movants submitted a corrected Joint Motion *in Limine* on September 23, 2009.[1]

18. In Decision No. C09-1101 issued on September 28, 2009 we described the first argument in the Motion *in Limine* as "the issues related to the sufficiency of the advice letter and the notice provided by Public Service." *See* Decision No. C09-1101, ¶ 10. We then shortened response time to this aspect of the Motion *in Limine* to October 1, 2009 as follows:

> The deadline for Public Service to address the sufficiency of Advice Letter No. 1535-Electric in light of both statutory requirements and the Commission's rules **and** the sufficiency of

[1] As noted in Decision No. C09-1101, Movants' reliance on Rule 3002, 4 Code of Colorado Regulations (CCR), a rule applicable to "applications" and not suspended advice letter proceedings, is misplaced.

> customer notice in light of both statutory requirements and the Commission's rules is **October 1, 2009**.

Decision No. C09-1101, Ordering Paragraph 2 (emphasis in original). Public Service timely submitted a response on October 1, 2009, which response was supplemented by a Notice of Errata filed on October 2, 2009. No other party submitted a response.

19. The list of elements required to be set forth in an advice letter is not found in statute; instead it can be found in Rule 1210(c)(II) of the Commission's Rules of Practice and Procedure, 4 Code of Colorado Regulations (CCR) 723-1. Item (I) in this enumeration states that advice letter shall contain "[t]he name, telephone number, facsimile number, and e-mail address of the person to contact regarding the filing." Advice Letter No. 1535-Electric includes a name but it does not include telephone/facsimile/e-mail information of a Public Service representative.

20. Relevant statutes and Rule 1305(b), 4 CCR 723-1, provide guidance as to how the Commission should treat the apparent inadequacy of the standardized content used by Public Service in its advice letters. These provisions are in addition to the Commission's power to waive its own rules for good cause. *See* Rule 1003, 4 CCR 723-1. Specifically, § 40-6-111(3), C.R.S., provides,

> [t]he tariffs and schedule required by this title shall contain such information, and shall be published, filed, and posted in such form and manner as the commission by regulation shall prescribe; and the commission is authorized to reject any tariff or schedule filed with it which is not in the form required by this section and by such regulations conclusions.

21. Additionally, Rule 1305(b), 4 CCR 723-1, states, "[t]he Commission may, pursuant to § 40-6-111(3), reject any proposed tariff, price list, or time schedule that is not submitted in the format required by statute or the Commission's order or rules."

22. Neither of these provisions is mandatory. The Commission has the power to point out the technical deficiencies and still permit this suspended advice letter proceeding to continue forward to a final decision. While we recognize the Notice in this advice letter was inadequate, we determine it is in the public interest to allow the proceeding to continue. However, Public Service should take the necessary steps to ensure that all of the information required by Rule 1210(c)(II), 4 CCR 723-1, is contained in future advice letters.

23. Turning to the content of the customer notice, § 40-3-104(1)(c)(II), C.R.S., describes the mandatory content of the customer notice associated with an advice letter. This statute provides, *inter alia*, that customer notice "shall be sufficient if it . . . informs affected customers, other than residential and small business customers, where they may call to obtain information during the thirty-day period prior to the effective date of the proposed increases or changes concerning how such increases or changes will affect them." While this provision appears to set forth a required element, the primary purpose behind § 40-3-104(1)(c)(II), C.R.S., is to provide customers an opportunity to file "protests" for the purpose of assisting the Commission to decide whether to suspend an advice letter and set it for hearing. In this instance, the Commission did suspend Advice Letter 1535-Electric. *See* Decision No. C09-0512. For all intents and purposes, therefore, Movants' claims on this issue were moot at the time the Joint Motion *in Limine* was filed.

24. Although Advice Letter 1535-Electric was suspended by Decision No. C09-0512, it is necessary to point out we disagree with Public Service's claim that the provision of "call

information" is satisfied by following statement: "[t]he proposed and present tariffs are available for examination and explanation at the business office of Public Service Company located at 550 15th Street, Denver, Colorado 80202." Future customer notice associated with advice letters should contain a telephone number so as to avoid any potential future dispute regarding the adequacy of customer notice.

25. Finally, it is worth pointing out that 27 intervenors, via eight separate intervention requests, were aware of the proposed changes to Public Service's "Easements and Environmental Agreements" tariff section. These intervenors represent only a subset of all intervenors contesting Public Service's proposed rate increase and rate design changes. Thus, the Commission agrees with Public Service that the customer notice was sufficient to ensure the issues raised by its advice letter will be thoroughly debated in both Phase I and Phase II of this matter.

26. In conclusion, having already suspended and set Public Service's Advice Letter No. 1535-Electric for hearing and conducted a hearing on Phase I (and having planned a hearing on Phase II), we find Public Service's Advice Letter No. 1535-Electric and the associated customer notice both contain sufficient information to comply with the applicable provisions of the Public Utilities Law and/or Commission rules. Therefore, the Joint Motion *in Limine* will be denied as to its first argument.[2]

[2] As noted in Decision No. C09-1101, the remaining arguments presented in the Joint Motion *in Limine* will be dealt with in conjunction with our analysis of the Phase II issues.

D. Preliminary Evidentiary Rulings

27. Public Service filed two motions seeking to limit the inclusion of certain testimony and exhibits filed by intervenors in this docket. On October 13, 2009, Public Service filed a motion to strike answer testimony and exhibits of Ms. Glustrom, Mr. Milton, Ms. Burchell, Mr. Ells, and Mr. Pomerance. On October 21, 2009, Public Service filed a motion seeking to strike the entirety of Mr. Sanzillo's surrebuttal testimony filed on behalf of ACT. (Collectively, Motions to Strike.)

28. The intervenor testimony challenged in these motions is varied. The Commission therefore undertook a line-by-line analysis of the challenged testimony in to evaluate whether it possessed some probative value in this particular rate setting proceeding. *See* Rule 1501(a) of the Rules of Practice and Procedure, 4 CCR 723-1. The Commission then provided oral rulings on the Motions to Strike from the bench prior to commencing hearings. Those rulings are summarized here.

29. The Commission granted the Motions to Strike in part. The excluded testimony falls into three general categories. First, many of the intervenors filed testimony that constitutes a collateral attack on the Commission's prior decision to grant Public Service a CPCN for Comanche 3. Much of this testimony argues that bringing Comanche 3 online would create excess capacity, constituting a "changed circumstance" that would render operation of the plant

improper under Rule 3613(d) of the Rules Regulating Electric Utilities, 4 CCR 723-3.[3] The Commission believes these arguments are not properly raised in this proceeding. A utility acting in accordance with an approved resource plan enjoys a presumption that its actions are prudent. The Commission may disallow expenses or investments made by a utility pursuant to an approved resource plan only if an intervenor overcomes this presumption, showing the utility actually deviated from the approved plan, or if an intervenor presents compelling evidence that "due to changed circumstances timely known to the utility or that should have been known to a prudent person, the utility's actions were not proper." Rule 3613(d)(I)(B), 4 CCR 723-3 (emphasis added).

30. Certain intervenors argue that, due to the decrease in consumer demand for electricity caused in part by the weak economy, circumstances have changed, rendering inclusion

[3] Rule 3613(d) of the Rules Regulating Electric Utilities, 4 CCR 723-3, states, in relevant part:

> (d) Effect of the Commission decision. A Commission decision specifically approving the components of a utility's [resource] plan creates a presumption that utility actions consistent with that approval are prudent.
>
> (I) In a proceeding concerning the utility's request to recover the investments or expenses associated with new resources:
>
> (A) The utility must present prima facie evidence that its actions were consistent with the Commission decisions specifically approving or modifying components of the plan.
>
> (B) To support a Commission decision to disallow investments or expenses associated with new resources on the grounds that the utility's actions were not consistent with a Commission approved plan, an intervenor must present evidence to overcome the utility's prima facie evidence that its actions were consistent with Commission decisions approving or modifying components of the plan. Alternatively, an intervenor may present evidence that, due to changed circumstances timely known to the utility or that should have been known to a prudent person, the utility's actions were not proper.

of costs associated with the Comanche 3 plant improper because operation of the plant is no longer absolutely necessary to meet current forecasts of 2010 load. The Commission does not believe Public Service knew about or should have predicted the unprecedented current economic situation and its resulting impact on electricity demand.[4] The Commission finds that these arguments, as well as arguments attacking the prudency of building Comanche 3, are not relevant to this rate setting proceeding.[5] As such, the following portions of testimony were struck:

- Glustrom Answer; page 5, line 20 through page 6, line 3
- Glustrom Answer; page 26, lines 15 through 23
- Glustrom Answer; page 27, lines 1 through 12
- Milton Answer; page 1, lines 9 through 11
- Milton Answer; page 2, line 7 thorough page 4, line 11
- Burchell Answer; page 3, lines 1 through 3
- Eells Answer; page 16, lines 11 through 13
- Pomerance Answer; page 12, lines 1 through 11

31. The second category of excluded testimony presents arguments about fuel cost and availability. The Commission believes these are resource planning issues, properly addressed in a resource planning docket, rather than a rate setting proceeding. Therefore, the following portions of testimony were struck:

- Glustrom Answer; page 6, line 13 through page 21, line 8
- Glustrom Answer; page 22, line 3 through page 23, line 23
- Glustrom Answer; page 29, lines 2 through 11
- Glustrom Answer; Attachments 4 through 15
- Burchell Answer; page 7, line 1 through page 9, line 11
- Eells Answer; page 18, line 17 through page 19, line 13
- Eells Answer; page 20, line 1 through page 25, line 4
- Sanzillo Surrebuttal; page 5, line 8 through page 29, line 6
- Sanzillo Surrebuttal; page 34, lines 19-20

[4] While the Commission finds this particular Rule 3613(d) capacity argument to be improper and excludable, it declines to exclude other Rule 3613(d) arguments, which it believes are properly presented.

[5] Under this same reasoning, the Commission rejected several Hearing Exhibits offered by Ms. Glustrom during hearing. These exhibits made arguments or provided evidence about coal costs, coal supply, and the construction of Comanche 3. The Commission deemed the following Hearing Exhibits to be outside the scope of this proceeding and thus did not admit them into the record: 87-89; 119; 165; 168-74.

- Sanzillo Surrebuttal; Exhibits TS-1 and TS-2

32. Third, the Commission believes portions of the challenged testimony presenting arguments or recommendations related to customer billing should be excluded. The following portions of testimony were excluded from consideration in Phase I of this docket, because the Commission believes they are properly considered in Phase II of this proceeding:

- Glustrom Answer; page 28, lines 10 through 14
- Glustrom Answer; page 28, lines 20 through 23
- Pomerance Answer; page 3, lines 1 through 10
- Pomerance Answer; page 3, lines 15 through 19
- Pomerance Answer; page 6, line 4 through page 10, line 5
- Pomerance Answer; page 11, lines 1 through 23

33. There is no need for parties to re-file the portions of testimony related to customer billing, as the Commission will consider them in Phase II of this Docket.

34. The Commission denies Public Service's Motions to Strike as to all other portions of the challenged testimony, finding the testimony contained within those challenged portions is relevant to Phase I of this rate setting proceeding. In addition, the Commission rejects Public Service's argument that the entirety of Mr. Sanzillo's surrebuttal testimony, filed on behalf of ACT, should be excluded as improper late filed answer testimony. The Commission believes Public Service experiences no prejudice from inclusion of this testimony, particularly because live surrebuttal testimony was already allowed by the Commission.

35. As part of its Motions to Strike, Public Service identified and offered to delete certain portions of its rebuttal testimony that were responsive to excluded answer testimony. The

Commission determines the following portions of rebuttal testimony filed on behalf of Public Service are responsive to excluded intervenor testimony and may, therefore, be withdrawn:

- Hyde Rebuttal; page 6, lines 8 thorough 12
- Hyde Rebuttal; page 7, lines 18 through 21
- Hyde Rebuttal; page 32, line 22 through page 33, line 6
- Hyde Rebuttal; page 37, line 18 through page 39, line 22
- Hyde Rebuttal; page 42, lines 7 through 9
- Hyde Rebuttal; page 42, lines 10 through 16
- Love Rebuttal; page 2, lines 4 through 17
- Love Rebuttal; page 7, line 16 through page 14, line 7
- Love Rebuttal; page 15, lines 8 through 15
- Love Rebuttal exhibits JML-2 and JML-3

E. Settlement Agreement

36. On November 18, 2009, a Settlement Agreement in this docket was filed by Public Service, Staff, CEC and EOC (collectively, Settling Parties). The Settlement Agreement calls for a $136 million increase in the revenue requirement. The agreement settles a number of issues in the case, including return on equity, capital structure, the treatment of SmartGridCity[6] and certain depreciation issues. No other parties support the agreement, although some were silent on their view of the settlement in their Statements of Position.

37. Post-hearing settlements are rare, but not unheard of. Since the hearings had already concluded, the Commission has a broad range of inputs it may use to decide the issues in this case. In effect, the Settlement Agreement becomes a Joint Statement of Position by the Settling Parties. Since the hearings covered the entire breadth of the case, we are not limited in our review to only the Settlement and its issues.

38. Because the Settlement Agreement serves effectively as a Joint Statement of Position, the Commission will consider it along with the other evidence presented in this case for

[6] SmartGridCity is a Registered Trademark of Xcel Energy, Inc.

each disputed issue. However, the Commission is cognizant of the fact that the Settlement represents a compromise reached by the Settling Parties.

F. Revenue Requirement

39. The Commission's final identification of an appropriate revenue requirement is a complicated process, based on a number of factors, which we will briefly identify before considering them in detail.

40. We determine that the revenue requirement increase for Public Service should be $128.3 million, minus $61,364,353 for Comanche 3. This results in a total General Rate Schedule Adjustment (GRSA) of 45.01 percent. When fully adjusted for inclusion of Comanche 3 the GRSA will increase to 51.87 percent, including the property tax impacts. This is based on the Settlement figure of $136.0 million, with the following adjustments: removal of a portion of the reach-forward in distribution plant (-$4.8 million), inclusion of long term debt payments in the calculation of cash working capital (-$2.2 million), a change in the amortization period for rate case expenses (-$0.4 million), a modification in the production tax credit (-$0.6 million), and the removal of the disallowance for employee recognition expenses (+$0.1 million).

41. We find the return on equity should continue to be 10.5 percent. The cost of debt shall be set at 6.21 percent, as agreed to in the Settlement. This was based on the actual observation of a debt issuance by Public Service in June 2009. Using the Settlement's agreement on the capital structure, this results in a rate of return on rate base of 8.72 percent. Each of these decision items is explained more fully below.

1. Test Period

42. The choice of a test year is one of the key elements of utility rate making. Through the test year we determine the interrelationships of revenues, expenses, and rate base

that will yield just and reasonable rates and will offer the utility a chance to earn its rate of return. Using a test year is an attempt to discern the relationship among revenue, expenses and rate base that is representative of what the utility faces when the new rates go into effect.

43. Various options exist in the creation of a representative test year. Many state commissions use what is called a historic test year (HTY), using revenues, expenses, and rate base from some historical period. Other commissions use what is called a future test year (FTY), in which forecasts are used to estimate the revenues, expenses and rate base for a future period.

44. There are other hybrid approaches as well, where HTYs are modified for known changes due to occur after the HTY concludes. This case presents a perfect example of such adjustments, where parties such as Staff, the OCC, CEC and CF&I, among others, all agree it is appropriate to overlay new capital investments onto the 2008 HTY. While parties vary on the exact *pro forma* adjustments, all take the approach that using an unadjusted 2008 HTY is not appropriate given the known additions to Public Service's 2008 HTY.

45. In this case, Public Service proposed to use a 2010 FTY, arguing a FTY better advances the public policy goals of matching the incurrence of costs with their recovery from customers and providing better price signals to customers. It also stated the FTY provides a more reliable basis for setting rates than using an HTY. It points out that the use of a FTY is not unusual, as many jurisdictions use FTYs to set rates. According to Public Service, a FTY minimizes regulatory lag, thereby providing Public Service with a reasonable opportunity to earn its authorized return on equity.

46. Public Service believes using a FTY facilitates utility investments that benefit customers over the long run. It states, contrary to common criticisms, a FTY does not weaken the utility's incentive to reduce its costs and operate efficiently. Also, Public Service argues that

a FTY reduces the differences in cost recovery between Company-owned generation and purchased generation under the current regulatory structure, thereby placing the two alternatives for securing generation resources on a more even playing field.

47. Staff, the OCC, CF&I, CEC, FEA, Climax, ACT and Ms. Glustrom unanimously oppose the use of a FTY. Staff and CEC argue the FTY is virtually impossible to audit. The OCC characterizes projections of revenues and expenses as inherently full of uncertainty and argues the existence of regulatory lag in an HTY creates significant incentives for the utility to be as efficient as possible. Climax points out that the FTY creates an incentive for the company to overestimate its expenses and understate its revenue forecast. Parties argue the HTY is a time-tested regulatory principle that offers an easier ability to audit both the historic numbers as well as any *pro forma* adjustments that are overlaid on the HTY.

48. The Settlement Agreement uses the 2008 HTY, as filed by Public Service, with a number of adjustments, including rate base adjustments for Comanche 3, Comanche 1 and 2 pollution control equipment, transmission upgrades for Comanche 3, Fort St. Vrain Units 5 and 6, and the investments from SmartGridCity. The Settlement also includes the forecasted incremental investments in distribution through 2010.

49. The test year utilized in the Settlement almost begs to be called a hybrid. While it is based on the 2008 HTY cost of service model, there are significant overlays and inclusions to account for known changes from 2008. Also, the Settlement proposes adjustments that exceed what this Commission has approved in the past, going beyond the traditional cut-off timeframes.

50. While we accept the general approach advocated in the Settlement, to some degree we are uncomfortable with the mismatch of revenues, expenses, and rate base contained in the Settlement. The approach taken by the parties was to reach forward only on a subset of

incremental additions to rate base but to leave expense and revenue levels essentially as derived from the 2008 HTY. Therefore, the three components of the test year do not match. Essentially, the Settlement is an attempt to capture certain incremental investments brought into rate base in 2009, and a separate reach forward to capture incremental distribution investment in 2009 and 2010, but without reaching forward to capture changes in revenues or expenses.

51. We understand the settlement process can be difficult and complicated, and we appreciate the parties' efforts to bring us a more robust set of regulatory principles underlying the settled revenue requirement. However, the degree to which the incremental distribution investment is captured so far into the future, without a better matching from revenues and expenses, is troublesome. We therefore adopt the Settlement's test period, but will cap the reach forward on investment in distribution only to June 30, 2009.[7] This reduces the revenue requirement by $4.752 million.

52. With respect to the use of a FTY in the next Public Service rate case, the Settlement states:

> The Settling Parties recognize that the Company expects to file a FTY COS in its next Phase 1 electric rate case. The Company agrees to provide a HTY COS and a deviations analysis similar to one provided in Hearing Exhibit No. 187 as part of its direct case filing. In addition, the Company and any interested party agree to work on reporting requirements with respect to budget and actual data in order to facilitate review of future cases. The Settling Parties reserve their right to argue any position regarding the appropriateness of a FTY in the Company's next Phase I electric rate case.

[7] Commissioner Baker would adopt a Future Test Year in this proceeding because he believes the mismatch in revenues and investments is structural in nature. In the alternative, Commissioner Baker would not restrict the reach forward beyond the terms of the Settlement.

53. We adopt this aspect of the Settlement, and urge the settling parties to devise a program to meet the expectations of the Settlement. We expect Public Service will provide a comparison of any proposed FTYs and HTYs in the first stages of any forthcoming rate setting proceeding. The Commission believes supplying this information early in the process should allow intervenors to better analyze the differences between an HTY and a FTY.

54. From the testimony presented in this proceeding, it is apparent many intervenors felt disadvantaged in their attempts to review and audit the 2010 FTY proffered by Public Service. In fact, Staff did not perform a rigorous analysis of the 2010 FTY, which limited the Commission's ability to make balanced judgments regarding this issue. To ensure that does not happen in the next rate case, we urge Public Service and the intervenors to form a task force and initiate workshops and other information sharing venues where the appropriate reporting by Public Service can begin. We also encourage Staff and other parties to reach out to other state commissions where FTYs are used regularly and research best practices used by staff of those commissions.

55. Public Service's increases in sales and revenues are off sharply from what they were pre-2008. It is unclear how much of this drop is due to the economic conditions and what proportion might be a change in the demand for electricity stemming from energy efficiency or some other societal change. Simultaneously, Public Service has rolled significant investments into rate base this year and has continuing plans for distribution re-builds and resource acquisitions driven by its latest resource plan. In a period where revenues are not rising as much as expenses and investments, earnings attrition becomes a larger threat and a FTY would be one way to address that problem.

56. While the Commission does not adopt Public Service's proposed FTY in this proceeding, the identification of a test period is just one tool the Commission may use to ensure the Company's continued financial viability. The Commission notes that, while an FTY has not been used in the past, Public Service today enjoys favorable financial ratings, and the Commission understands the merit of regulating in a fashion that allows an efficient utility to maintain strong financial health and garner favorable analyst ratings.

2. Rate Base

a. Cash Working Capital

(1) Exclusion of Long Term Debt

57. Public Service, in its direct case, filed a calculation of cash working capital (CWC) that excludes interest payments on its long term debt from the calculation. In its answer testimony, OCC argues that there is no rationale for the exclusion and suggests these be included in the calculation. The Settlement, since it is built from Staff's 2008 HTY, is essentially consistent with Public Service's position.

58. We decline to adopt the Settlement's treatment of long-term debt interest payments in the calculation of CWC. We are persuaded by arguments raised by the OCC that the exclusion of CWC from that calculation is arbitrary. As the OCC points out, Public Service includes the following expenses in determining its working capital requirement: Operation and Maintenance (O&M) expenses, fuel expenses, purchased capacity expenses, federal income tax expenses, property tax expenses, sales tax expenses, franchise fee expenses and expenses charged to it by Xcel Energy Service, Inc. However, the Company excludes interest on long term debt.

59. Public Service states it does not include interest expense on long-term debt in its CWC calculation because the Commission determined in previous Public Service rate cases (Docket Nos. I&S 1640 and 96S-290G) that interest on long-term debt should not be included as a component in the CWC allowance. As stated in Decision No. C84-598, denying the inclusion of long term debt interest payments in CWC,

> In contrast, the reduction in earnings and TIER which is caused by including interest and preferred dividends as CWC components will create pressure on financial analysts to downgrade the Company's bond and equity ratings which is detrimental to ratepayers in the long run.

Public Service also states that if the interest payments are included in the CWC calculations, then dividend payments should be included as well.

60. In Decision No. C84-598, the Commission developed axioms which would indicate whether an expense item would be included in CWC:

> Staff witness Ekland postulated three axioms which support his theory of the proper components to be included in CWC: (1) CWC is money put forth to meet expenses; (2) the only factors that change the level of cash working capital are the net lag days between receipt of revenues and payment of expense, and the size of the cash expenses; (3) an out-of-pocket cash flow is not a CWC expense, if it flows to a second pocket of the same party. If an item meets the criteria of the first two axioms and is not eliminated by the third axiom then it should be included in cash working capital.

We believe interest on long-term debt meets these criteria and we therefore adopt this requirement. This results in a $2.2 million reduction in the Settlement revenue requirement.

61. We might agree with Public Service that dividend payments should be included in CWC for consistency with interest payments. While the argument has been made that Public Service does not pay dividends directly, we presume it transfers cash to Xcel Energy so that it can make those payments at a corporate level. We would encourage Public Service to elaborate

on this issue if it desires to file an application for rehearing, reargument, or reconsideration (RRR).

(2) Revenue Lag Days

62. Revenue lag days are used by Public Service in calculating its CWC needs. Public Service first segregates bills by customer class and determines the number of days from the mid-point of the service period to the date that the bill was paid (plus one-half day), and calls that number the number of revenue lag days associated with that bill. Public Service next calculates the mean of the revenue lag days for all bills in each customer class and weights those means by the revenue associated with each class. It then adds the weighted lag days of all classes together, to calculate a single number of revenue lag days for all customers.

63. The OCC recommends that Public Service use 34.89, rather than 41.47 revenue lag days, in calculating its CWC requirement. This number of revenue lag days assumes non-residential customers pay their bills on the due date. The OCC concluded Public Service's method of calculating revenue lag days – which did not consider the size of the bills, but only the date on which they were paid – was systematically biased. In response to discovery, Public Service admitted it does not charge a late fee to non-residential customers who pay after the bill due date but before the next bill is generated. As a result, the OCC contends that Public Service's smaller customers provide a substantial subsidy to its larger customers.

64. According to Public Service, the OCC did not re-run the lead-lag study to develop its proposed imputed 34.89 revenue lag days, but rather adopted Public Service's calculated revenue lag of 39.27 days for residential customers and 32.2 revenue lag days for non-residential customers, assuming all such customers pay their bills exactly on the due date. Public Service re-ran the lead-lag study using the traditional "dollar-days" methodology and calculated total lag

days of 42.56, as compared to the 41.47 revenue lag days proposed by Public Service in its direct case. Public Service further incorporated the variation to the "dollar-days" method recommended by the OCC by performing a second weighting based on the ratio of each record's dollar-days by the total group dollar-days, which yielded an unreasonable result of 70.87 lag days.

65. With respect to the OCC's assumption that non-residential customers pay their bills on the due date, Public Service believes the OCC's recommendation effectively denies any CWC allowance related to non-residential customers paying their bills after the bill due date. Public Service states it does not receive any benefit from the late payment fees its collects and is not compensated for the time value of money associated with customers paying late.

66. We reject the proposal advanced by the OCC. The OCC's position requires the assumption that non-residential customers always pay on the due date exactly. Absent any data proving this is the case, we reject the proposed adjustment. Moreover, it appears that when Public Service re-ran its study based on the proposed changes by the OCC, an abnormally high number of lag days was found.

b. Comanche 3

67. During this docket a number of parties expressed concern about the timing of cost recovery for Comanche 3. Public Service filed this case on May 1, 2009 with an estimated in-service date for Comanche 3 of November 1, 2009. However, subsequent to that filing, Public Service experienced a number of construction delays. As this docket progressed, it became apparent that the delays were significant enough to warrant reexamining the Comanche 3 in-

service date and considering when it would be appropriate to allow Public Service to place the plant in rate base as a used and useful generation asset.[8]

68. A number of parties have correctly argued that cost recovery for Comanche 3 should depend on when the asset is used and useful and is delivering electricity to the grid. While we support the inclusion of assets outside of the HTY in this case, we believe cost recovery for an asset should not occur until such time that the asset is used and useful. In this case, we have included investments that are not in-service during the test year, such as the gas turbines at Fort St. Vrain.

69. In Decision No. C09-1283, mailed on November 13, 2009, we ordered an update from Public Service on the projected in-service date of Comanche 3. In its Update, filed on December 14, 2009, Public Service identified no firm in-service date for Comanche 3, but stated with certainty that the plant will not be in-service by January 15, 2010. We then scheduled a status conference for December 16, 2009. *See* Decision No. C09-1399, mailed December 15, 2009.

70. During that Status Conference, representatives of Public Service presented the Commission with an update on the status of the construction of Comanche 3. Public Service also put forth a preliminary proposal on how this delay could be reflected in rates, *i.e.*, a three-step GRSA to be effective on January 1, 2010.

71. In light of the developments mentioned above, we reopened the evidentiary record in this docket to address the issues related to the status of bringing Comanche 3 online. We

[8] Commissioner Baker was not present for the deliberations on the Comanche 3 GRSA phase –in.

scheduled an evidentiary hearing to discuss the final proposal by Public Service on how the delay in bringing Comanche 3 online should be reflected in rates.

72. We held a discovery conference on December 18, 2009, chaired by Commissioner James Tarpey. At that conference, Public Service explained its proposal, which consisted of staged GRSA increases to account for the delay in Comanche 3's in-service date. The Company discussed the expenses and rate base adjustments it was using in the various stages of the phased-in GRSA. In this proposal, Public Service tied the first GRSA increase to the "in service" date, which it defined as the first 24 hours when Comanche 3 ran all systems with stability.[9]

73. The Commission held a hearing regarding the proposal on December 22, 2009. At that hearing, parties presented testimony and arguments regarding Public Service's proposal. Those arguments focused primarily on Public Service's definition of the "in service" date. Staff witness Podein argued Public Service's identified "in service" date did not adequately correspond to when the plant would become "used and useful." In the alternative, Ms. Podein urged the Commission to adopt the Commercial Operations Date (COD) as the trigger for the first GRSA increase. Ms. Podein argued the COD is the industry standard for determining the commissioning of a plant. All other intervening parties supported this proposed alternative "used and useful" date.

74. Public Service opposes any change to its proposed "in service" date, arguing its definition of "in service" has remained consistent throughout these proceedings. In Public Service's opinion, parties could have raised concerns about its definition of "in service" prior to the supplemental hearings.

[9] This Proposal is presented in Public Service's Proposal for Adjusted General Rate Schedule Adjustment Riders, filed on December 17, 2009.

75. The Commission recognizes the timing of this Docket has created difficulties for both Public Service and for intervenors. Public Service is correct in that it has consistently used the same definition for "in service" throughout this proceeding and should have, therefore, enjoyed some certainty that this formulation was uncontested. However, no party challenged Public Service's definition of "in service," in large part because it was not a material issue in this case while all parties assumed Comanche 3 would become operational during 2009.

76. In Decision No. C81-1999, when faced with a similar issue, the Commission considered a plant "used and useful" when it had "completed 24 hours of continuous operation at near rated capacity with all necessary supporting systems operating normally." Decision No. C81-1999, at 27. We find that this is a reasonable standard by which to evaluate whether a plant is "used and useful" to ratepayers and apply it here. We will hereinafter refer to this date as the "rate base inclusion date."

77. We therefore adopt Public Service's proposal with some significant changes. On January 1, 2010, Public Service will be entitled to a GRSA of 45.01 percent. This GRSA may be increased to 51.01 percent on or after Comanche 3's rate base inclusion date. Finally, the GRSA may be increased to 51.87 percent on January 1, 2011, to account for changes in tax treatment of Comanche 3.

78. However, we retain some concerns about Comanche 3's operations and we wish to receive additional information about Comanche 3 and its progress. First, Public Service shall, by January 6, 2010, provide a detailed description of each Activity listed in Attachment No. 6.0 to the Semi-Annual Progress Report for the Comanche Expansion Project, filed with the Commission on December 14, 2009 in Docket No. 05M-511E (Attachment 6.0). The

explanation should fully describe each Activity and identify and describe the major component sub-tasks of each Activity.

79. Second, beginning on January 8, 2010, and each week thereafter until one week after the Commercial Operation Date, the Company shall provide the Commission with the following:

- A current Level 2 Critical Path Schedule showing all critical path activities listed in Attachment 6.0 with Start Dates on or after December 15, 2009. The Schedule shall use the same format as Attachment No. 6, except that the Schedule shall show the percent complete for each Activity. For completed activities it shall show the completion date.
- An electronic copy of the Level 2 Critical Path in native file format, assuming the report was created in Microsoft Project. If the native file format is not Microsoft Project, the Company shall identify the underlying software and provide the file as exported to Microsoft Excel.
- A narrative statement of the Overall Project Status similar to the report provided in the Semi-Annual Progress Report.
- A report on the amount of "test energy" produced by the facility each day.
- A report on the peak capacity reached by the facility each day.
- A copy of any document provided to the Finance Council on any individual member thereof or to the Board of Director that references activities listed in Attachment 6.0.

80. Further, the Commission believes it is appropriate to have some involvement in the GRSA step-up process. Therefore, the Commission orders Public Service to make a compliance filing on not less than three business days' notice providing the Commission with information about Comanche 3's satisfaction of the standard for rate base inclusion, in order to allow the Commission an opportunity to reject the GRSA increase if it believes Comanche 3 is not "used and useful" at that time.

81. The Commission wishes to note that classification of an asset as "used and useful" is never irreversible. In other words, if the Commission deems Comanche 3 "used and

useful," now but finds circumstances have changed at some later date, it may revisit its prior finding that allowed the asset to be placed in rate base.

c. Unbilled Revenues

82. Unbilled revenues are an adjusting entry made at the end of an accounting period to allocate revenue to the period in which they are actually applicable. The OCC argues Public Service's method of removing unbilled revenues from the revenue requirement is flawed because it fails to match each month of revenue with the corresponding month's expenses.

83. In Rebuttal testimony, the Company argues its revenue requirement includes 12 months of expenses and 12 months of revenue, which is sufficient because those 12 months need not be the exact same 12 months. Public Service also points to a long-standing Commission precedent for recognizing only billed sales.

84. We find no reason to reverse our longstanding practice of including only billed sales in test year revenues. Therefore, we accept Public Service's method of calculating the unbilled revenue adjustment.

d. Rate of Return

85. The rate of return, as set through a regulatory ratemaking process, is intended to support the utility's financial integrity, allowing the utility to maintain its credit standing and attract necessary capital. In addition, the rate of return ensures the utility receives earnings within the range enjoyed by other companies facing similar risks. The regulatory goal is to identify a rate of return that is fair and reasonable to both consumers and the Company.

86. The overall rate of return on rate base we adopt is 8.72 percent.[10] This overall rate of return or weighted average cost of capital (WACC) was calculated based on a 10.50 percent return on equity and the capital structure agreed to by the parties to the Settlement.

87. The rate of return consists of a variety of elements, which we will discuss below.

(1) Return on Equity

88. In its direct testimony, Public Service argues a reasonable a reasonable range for its return on equity (ROE) is between 11.00 percent and 12.00 percent. Within this range, Public Service requests the Commission approve an 11.25 percent rate of return on common equity

89. The OCC, in its answer testimony, identifies a reasonable range for Public Service's ROE as 7.00 percent to 10.00 percent. Based on its analysis, the OCC recommends an ROE of 9.75 percent.

90. In its answer testimony, CEC recommends an ROE range of 9.60 percent and 10.40 percent. Based on its analysis, CEC suggests an ROE of 10.00 percent.

91. Staff's answer testimony also suggests an ROE range of 8.80 percent and 10.85 percent. Staff proposes a specific ROE of 9.84 percent.

92. Under the Settlement, the Company's authorized ROE would remain unchanged from the current level of 10.50 percent. As reflected in pre-filed testimony and evidence received at the hearing, the authorized ROE represents a significant factor in the ultimate determination of the Company's cost of service. The Settlement describes the analytical approaches employed and results achieved by the Settling Parties' respective witnesses.

[10] The WACC of 8.72 percent is found on Attachment A, (Settlement Agreement) page 3 of 5, line 27, under the column labeled "10.50 percent ROE Retail Jurisdiction."

93. Public Service believes an increased ROE is important, given its continued large levels of planned capital investment over the next four years. However, in the settlement, Public Service concedes that continuation of the currently authorized 10.50 percent return would signal the investment community that the Colorado regulatory environment remains stable.

94. The Settlement also contains a provision that the 10.50 percent ROE and Public Service's current capital structure will be used to calculate the Transmission Cost Adjustment (TCA), Renewable Energy Standard Adjustment (RESA) and the Demand Side Management Cost Adjustment (DSMCA).

95. In their statements of position, FEA, Ms. Glustrom, Climax and CF&I argue against accepting the Settling Parties recommendation of a 10.50 percent ROE and instead advocated for an ROE at or below 10.00 percent. Additionally, the OCC, in its statement of position, advocates an ROE of 9.75 percent.

96. The determination of the cost of the common stock portion of a utility's capital structure is a difficult and complex task, since the utility has no fixed contractual obligation to pay dividends to its common shareholders. To be sure, equity capital has a market cost in the sense that there is always a going rate of compensation which investors expect to receive for providing equity capital, but it is not a cost that is directly observable from market or accounting data.

97. We turn to *Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia*, 262 U.S. 679 (1923), and *Hope Natural Gas Co.*, 320 U.S. 591, for guidance on evaluating the fairness or reasonableness of a return on equity. Several tests articulate how a regulator may determine the fairness or reasonableness of the rate of return. These tests include evaluating whether the rate of return is (i) similar to that of other financially sound businesses having

similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to satisfy its capital requirements so that it can meet the obligation to provide adequate and reliable service to the public.

98. Based on the record in this proceeding, as well as the guidance set forth *Bluefield* and *Hope Natural Gas* cases, we find that a rate of return of 10.50 percent on equity is fair and reasonable, commensurate with rates of return on investments of other enterprises having corresponding risks, and sufficient to maintain financial integrity and attract equity capital in today's market.[11] This is the return on equity that has been afforded Public Service since its 2006 rate case. During this period Public Service has experienced financial strength as evidenced by its improving credit ratings by various credit rating agencies, such as Standard and Poor's.

(2) Capital Structure

99. In its direct testimony, Public Service recommends a capital structure for projected test year, ending December 31, 2010, of 41.95 percent long-term debt and 58.05 percent common equity.

100. The OCC, in its answer testimony, recommends two capital structures. The first capital structure recommendation is based on an HTY ending December 31, 2008, and consists of 46.65 percent long-term debt, 0.35 percent preferred stock, and 53.00 percent common equity. The OCC bases this calculation on an average of Xcel Energy Inc.'s and Public Service's capital structures. The second capital recommendation is based on a projected test year ending

[11] While the Commission did not adopt an acceptable range of ROE, the adoption of 10.50 percent is not intended to serve as a cap.

December 31, 2010, and proposes 47.31 percent long-term debt, 0.25 percent preferred stock, and 52.44 percent common equity.

101. FEA recommends adjustments to both a FTY and an HTY capital structure in order to account for cost savings from financing using short-term debt. FEA recommends a capital structure for an HTY ending June 30, 2009, containing 42.53 percent long-term debt, 0.86 percent preferred stock and 56.61 percent common equity. For the FTY ending December 31, 2010, FEA recommends a capital structure of 44.09 percent long-term debt, 0.80 percent preferred stock and 55.11 percent common equity.

102. Staff began its calculation by using the Company's 2008 HTY Cost of Service Study, and then adjusted the historical capital structure to reflect Public Service's forecasted average capital structure for 2010. Public Service disagreed with Staff's methods, advocating that, if revenue requirements are developed using the 2008 historical test year Cost of Service Study, the appropriate capital structure should be the Company's adjusted book capital structure as of December 31, 2008.

103. In the Settlement, the Settling Parties propose to compromise by reflecting 50 percent of the value of the Staff's adjustment to the historical test year capital structure in the calculation of the settled revenue requirement. However, although the settled revenue requirement reflects this compromise, Staff and Public Service also agree to continue the Commission's traditional method of calculating the Company's rider recovery going forward and for purposes of the earnings test, which consists of adjusting the Company's current book capital structure to remove the effects of short term debt and non-regulated activities.

104. We find the terms of the Settlement Agreement, in which the cost of long-term debt is 6.21 percent, the cost of common equity is 10.50 percent, and the weighted average cost

of capital is 8.72 percent, are just and reasonable and will therefore be adopted. Based on these calculations, we find the debt to equity ratio in the capital structure to be 41.44 percent long-term debt and 58.56 percent common equity.

(3) Cost of Debt

105. Public Service and Staff agree that the Company's weighted average cost of debt, after taking into account the Company's $400 million bond issuance in June 2009, is 6.21 percent. Based on the record in this proceeding and the fact that no party contested this issue, we find that 6.21 percent is Public Service's average cost of debt.

(4) Cost of Capital

106. Capital costs are incurred by the utility in the provision of service to ratepayers. The sources for funding these capital costs are a combination of both long-term debt and equity funds. The resulting overall cost of capital is the product of weighting the individual capital costs (long-term debt and equity) by the proportion of each respective type of capital included in the Company's capital structure for regulatory purposes.

107. Once the capital structure has been calculated, the Commission must determine an overall rate of return allowance which will provide the Company with an opportunity to cover its interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital, be commensurate with the risk to which the Company's capital is exposed, and support reasonable credit quality.

108. We hold that the correct cost of capital is that which is calculated in the Settlement Agreement. The weighted average cost of capital in this proceeding will be

8.72 percent, which is calculated based on the settlement agreement Cost of Service Study data with adjustments based on a 10.50 percent return on equity.[12]

e. Earnings Test

109. The Settlement includes a provision for earnings monitoring that requires Public Service retain 25 percent of earnings in excess of 10.5 percent up to 10.75 percent; 50 percent of the earnings in excess of 10.75 percent up to 11 percent; 75 percent of earnings in excess of 11 percent up to 11.25 percent, and 100 percent of earnings in excess of 11.25 percent up to 11.5 percent. Public Service will refund 100 percent of any earnings in excess of 11.5 percent to retail customers. Many parties in this case argued for an earnings test if the Commission granted Public Service the use of the FTY.

110. We reject this provision of the Settlement. We understand many parties feel an earnings test provides an additional layer of consumer protection by automatically triggering refunds in the event of overearnings. However, because Staff of the Commission can institute a complaint in the event that Public Service begins to over earn, we believe this protection exists already. The Company's ability to occasionally and temporarily over earn without automatic refund provisions offsets periods of under earning and is a strong incentive for efficiency. Often the use of an earnings test is more appropriate in the case of mergers, where unknown impacts could affect the level of merger efficiencies and resulting savings. In more orthodox situations such as this case, earnings monitoring generally does not reach the level that triggers sharing and in fact can act as a perverse incentive for the utility.

[12] *See* Settlement Agreement, Attachment A, page 3 of 5, line 27.

3. Expenses

f. Treatment of Cameo, Zuni and Arapahoe

(1) Removal Costs and Future Cost Recovery

111. In its direct case, Public Service submitted an update to the 2008 Depreciation Study previously provided to the Commission. The update pertains only to the steam production assets, with revised life and removal cost estimates provided for Arapahoe Units 3 and 4, Cameo Units 1 and 2, and Zuni Units 1 and 2. It is the basis for the following proposed changes to the Company's existing depreciation rates and accruals for steam production plant:

- Revise the retirement date for Arapahoe Units 3 and 4, Cameo Units 1 and 2, and Zuni Units 1 and 2.
- Update the estimated removal cost for the units listed above.
- Realign the accumulated reserve for depreciation to moderate the impact of the first two changes and to better align the reserve with current life statistics.
- Use a recovery period for the asset cost and expected removal costs for these three plants that is longer than the expected useful life to minimize the increase in depreciation for the new removal estimates.

112. Staff initially opposed the Company's proposed changes and explained the revised cost to dismantle these units is an increase of approximately $95 million, more than six hundred percent greater than the original amount provided to the Commission. Staff recommended the Commission disallow any increase in depreciation for Arapahoe Units 3 and 4, Cameo Units 1 and 2, and Zuni Units 1 and 2. Additionally, Staff believed Public Service should be required to file an application for each retired plant for a date certain schedule for the competitive acquisition of the dismantling and removal of these units. Under this proposal, the Company would be allowed to recover actual dismantling costs for these units in excess of those collected through current and past depreciation rates through an amortization only once the dismantling is completed.

113. In the settlement, the Company agreed to withdraw its updated estimate of removal costs associated with the anticipated retirement of Cameo 1 and 2, Arapahoe 3 and 4 and Zuni 1 and 2 from the cost of service. The Settlement proposes to update the removal cost estimates for future plant retirement by submitting a separate application for each plant to be retired. These site specific decommissioning plans will include the following information: (1) a Request for Proposal (RFP) for competitive acquisition of dismantling and removal services; (2) a proposed amortization period for the decommissioning costs to be recovered and the expected revenue requirements associated with such recovery; and (3) a proposed mechanism for recovery of the difference between the updated removal cost estimates and removal costs associated with these assets currently being recovered through base rates. The Settling Parties also request the Commission include in its order the following specific authorization for the Company:

1. Create and/or adjust a regulatory asset or liability for each plant by an amount equal to any difference between:
   a. the level of depreciation expenses using the removal cost being recovered through the base rates approved in this proceeding associated with three plants; and
   b. the level of depreciation expense using updated or revised removal cost estimates required to be recognized by the Company in accordance with GAAP (for financial reporting purposes).
2. To recover a return of and a return on such regulatory asset or refund of any regulatory liability balance through a separate rate mechanism to be established at the time the removal costs are finally determined and approved.

114. The OCC opposed the Company's initial positions and also opposes this settlement position. Initially, the OCC argued that when a utility does not remove a capital asset upon its retirement, the utility's customers will have over-paid depreciation expense. In its cross-answer testimony, the OCC disagrees with Staff's recommendation to require Public Service

begin the process of dismantling and removing all generating stations within one year of plant retirement, stating it is too expensive. The OCC believes that if Public Service has no legal or regulatory obligation to dismantle and remove plant, customers are better served if the Company does not collect depreciation dollars for the plant's dismantling and removal.

115. Regarding the Settlement position on removal costs, the OCC states the record is completely devoid of evidence that these plants need to be removed. The OCC is not convinced Public Service will dismantle and remove the facilities at Arapahoe, Cameo and Zuni. The OCC is concerned that, if they are not removed, the Company's customers would have overpaid removal costs.

116. ACT disagrees with the Settlement's treatment of depreciation, arguing it is arbitrary and capricious, not supported by any evidence in the record, and contrary to established jurisprudence. ACT believes Public Service's retail customers will be paying an unjust and unreasonable amount for depreciation with no guarantee of recovering this overpayment if Public Service over earns its return on equity.

117. We find it proper to allow the Company to withdraw its request for recovery of increased removal costs. The process of addressing removal costs on a site-by-site basis will allow the Company's applications to be reviewed specifically for that project rather than in a generic manner. As a result, we adopt this portion of the Settlement without modification.

(2) Depreciation Expenses Other Than Removal

118. The Company initially proposed increased depreciation rates for Cameo 1 and 2, Arapahoe 3 and 4, and Zuni 1 and 2 with the goal of recovering the total undepreciated plant balance for each of these units by the time each plant is expected to be retired. Staff and the OCC both advocated for the continuation of current depreciation rates. Further, the OCC

opposed the use of year-end 2008 plant in-service balances and instead supported the use of a 13-month average balance in calculating depreciation expense for the *pro forma* adjustment to the HTY.

119. The Settlement proposes depreciation rates for all of the Company's steam production plants including Cameo 1 and 2, Arapahoe 3 and 4, and Zuni 1 and 2. These rates shall be the same as those approved by the Commission in Docket No. 06S-234EG and used as the basis for the Company's revenue requirement calculations in Docket No. 08S-520E. Additionally, to the extent the Company is required to recognize a different level of depreciation expense for Generally Accepted Accounting Practices (GAAP) purposes than what is being recovered through its retail rates (due to use of a shorter estimated remaining life of these plants), the Settlement requests authorization for the Company to create a regulatory asset. The regulatory asset would be equal to the difference between the amount of depreciation expense being recovered through base rates and what the Company is required to recognize for GAAP purposes. Further, the Company would recover the return of and return on the regulatory asset in the Company's next Phase I electric rate case. The Settling Parties agree the length of time over which the regulatory asset will be recovered shall not exceed the life of each asset as reflected in current rates.

120. Under this Settlement, a 13-month average balance will be used to calculate depreciation expense. No party to this rate case opposed this provision of the Settlement. Because we believe this manner of calculation is reasonable, we approve this portion of the Settlement without modification.

(3) Cameo Project Costs

121. In its initial case, Public Service included $3 million in its rate increase request for the costs of a solar demonstration project at Cameo which is part of its Innovative Clean Technology (ICT) program. Through Rebuttal testimony, the Company reduced the amount to $2.25 million.

122. Both Staff and the OCC took the position that recovery of O&M costs for future ICT projects was premature, noting that in Decision No. C09-0472 the Commission concluded the Company was entitled to recover the costs of this project in an unspecified "future proceeding."

123. The Settlement allows the Company to defer such costs and recover them in rates approved as part of the Company's next electric Phase I rate case.

124. We accept the Settlement position withdrawing any request to recover Cameo costs in this rate proceeding.

g. Rate Case Expenses

125. In its direct case, Public Service seeks compensation for rate case related costs incurred to date, the estimated incremental costs of preparing and litigating this case, and the unamortized rate case expenses from the 2008 rate case in Docket No. 08S-520E, to be amortized over a period of two years.

126. The OCC advocates for a sharing of expenses between ratepayers and shareholders, arguing it would provide an incentive to limit these expenses. The OCC contends the current situation, which provides full recovery of rate case expenses in rates, requires customers to pay for Public Service to find ways to increase its rates and is not just and

reasonable. Additionally, the OCC proposed a three-year period of amortization for rate case expenses.

127. Ms. Glustrom also supports splitting costs between ratepayers and shareholders to provide an incentive to Public Service to avoid "running up the bill." Ms. Glustrom proposes that the Company bear at least half of its rate case expenses.

128. The Settlement allows the Company be permitted to amortize $2.6 million in rate case expenses over a two-year period beginning January 1, 2010.

129. We find recovery of rate case expenses to be a normal and legitimate activity for a regulated utility. A better course for controlling expenses is rigorous oversight, rather than splitting costs. The Company shall be permitted to amortize $2.6 million for rate case expenses over a three-year period effective January 1, 2010.

h. Residential Late Payment Fees

130. In its direct case Public Service proposed discontinuing its practice of donating to EOC the late payment fee revenue it collects from its residential customers. Instead, Public Service proposed crediting this revenue to the cost of service. In support of this change, Public Service argued that other low-income assistance services, such as the proposed Energy Assistance Program pilot proposed by Public Service, would mitigate the need for the bill payment assistance funding with this donation to EOC.

131. EOC states the existing practice of donating this revenue to EOC has been beneficial to the Company's low-income customers and should continue. EOC also argues the current donation by Public Service assists more of the Company's low-income customers than its proposed pilot program would.

132. The OCC, in answer testimony, recommends that Public Service credit one half of the residential late payment fee revenue to the cost of service and donate the other half to EOC. The OCC withdrew this proposal at hearing and agreed to support EOC's position. In its Statement of Position and Response to the Stipulated Settlement, the OCC clarifies it does not object to donating these fees to EOC but does oppose increasing the cost of service to adjust for this revenue not being included.

133. The Settlement supports donating all late payment fees collected from residential customers to EOC, starting January 1, 2010. Concurrent with this position the Settling Parties agree that the HTY cost of service should be adjusted to reflect a reversal of the revenue credit in the amount of $4 million, and that there should be a corresponding increase in the revenue deficiency and the GRSA.

134. As EOC points out in its testimony, when Public Service first proposed a residential late payment fee in Docket No. 06S-234EG, the associated revenues were not considered a "new revenue stream" for the Company. Public Service argued at that time that the financial benefit to ratepayers from these fees is not the revenue collected but the resulting reduction in operating costs associated with late payments. At the conclusion of that docket, Public Service began collecting residential late payment fees and contributing to EOC an amount equal to the after-tax value of these collected fees. This practice has continued, been reaffirmed and extended through settlements in subsequent rate dockets. We note the *status quo* practice is for Public Service not to treat these late payment fees as a revenue source. Thus, their collection and remittance to EOC has no net effect on the cost of service, while having a positive impact upon assisting the Company's low-income customers.

135. We also note the Settlement's treatment of late payment fees and donations to EOC maintains the *status quo*. We find this is a reasonable approach to handling the revenue resulting from residential late payment fees, as affirmed and reaffirmed in previous dockets. We thus adopt this portion of the Settlement.

i. TCA, DSMCA and AQIR Riders

136. We agree with the Settlement with respect to its treatment of the Transmission Cost Adjustment (TCA), the Demand Side Management Cost Adjustment (DSMCA), and the Air Quality Improvements Rider (AQIR). The Settlement allows Public Service to roll AQIR costs into base rates and to sweep much of the TCA and DSMCA costs into base rates. These were rather non-controversial issues in the case, although CEC initially opposed the movement of DSMCA costs into base rates.

j. Incentive Pay

137. Public Service included incentive pay, based on the four-year average of 2005-2008 payments in its initial revenue requirement calculation. The Company points out corporate earnings are a trigger for, not the basis of, the amount of payments. It states incentive compensation is calculated based on specific performance areas such as safety, reliability, and individual performance.

138. Staff and the OCC each protested the inclusion of incentive pay in the cost of service. Reasons for opposing this expense include: (1) the adjustment used by the Company was an average instead of an actual amount paid during the test period; (2) incentive compensation payments are not an extraordinary expense so no *pro forma* adjustment is required; (3) the structure of the incentive plan benefits shareholders, not ratepayers; and (4) the

adjustment proposed by Public Service is not a known and measurable change. Staff proposed a disallowance of $6,226,080 and the OCC proposed a disallowance of $6,199,655.

139. The Settlement included fifty percent of Staff's proposed disallowance, which is $3,113,040, in the cost of service.

140. ACT argues the Settlement's proposal to include fifty percent of incentive payments in Public Service's cost of service is arbitrary and without any basis in the record. ACT contends the Company did not demonstrate that the absence of a bonus payment in 2008 resulted in either the loss of personnel or an adjustment to base salaries. ACT also objects to employee incentive bonuses triggered by Xcel Energy Inc.'s financial performance.

141. We find that as part of the overall negotiated settlement package, the Settlement provision on this matter provides a reasonable resolution.

k. SERP Costs

142. The Company contends Financial Accounting Standards No. 87 Non-qualified Supplemental Executive Retirement Plan (SERP) payments are common in the utility industry and necessary to encourage continued employment with the Company. Public Service argues there is a benefit to ratepayers from this form of executive compensation because the Company is able to retain the qualified personnel necessary to manage the business.

143. Staff initially opposed any cost recovery for the SERP payments and made an adjustment of $1,925,792 to reduce these costs. Staff argues these retirement benefits for certain very highly paid Company executives and officers are in excess of the retirement benefits available to all other Company employees. Staff argued it was not reasonable or necessary for ratepayers to bear costs of executive benefits that exceed the treatment allowed for all other employees and states these expenses should be funded by shareholders.

144. The Settlement includes fifty percent of Staff's proposed disallowance, or $962,896, in the cost of service.

145. We find this compromise reflects a balanced approach to this matter.

l. Oil and Gas Royalties

146. Public Service contends the oil and gas royalties should be treated as non-utility revenue. The Company emphasizes this has been the treatment in all Company rate cases for approximately 30 years with the exception of the 2002 rate case in Docket No. 02S-315EG, when the full amount of oil and gas royalty revenues was included in the revenue requirement. However, to avoid further litigation of this matter, the Company proposed to share these revenues 50/50 with customers.

147. Staff initially proposed an adjustment of $1,210,850 to include all oil and gas royalty revenues in the calculation of the revenue requirement. Staff asserted that the land is recorded in rate base and property taxes paid on these lands is recovered from ratepayers. Further, § 40-3-114, C.R.S., requires that the Commission "ensure that regulated electric and gas utilities do not use ratepayer funds to subsidize nonregulated activities." Staff believes excluding oil and gas royalties from the revenue requirement also violates the principle of matching revenues and expenses because the revenues are booked in Public Service's unregulated activities while the expenses are recorded in regulated business activities.

148. The Settlement includes fifty percent of Staff's proposed revenue credit, which is $605,425, in the cost of service.

149. The OCC opposes any exclusion of these revenues from the Company's cost of service calculation. Its concern is that Public Service proposes retaining one-half of the proceeds of the oil and gas leases on its land, as a result of transferring property from the regulated entity

(Public Service Company of Colorado) to an affiliate (Fuelco). Since Public Service's customers were never appropriately compensated for the transfer of the property in 1975, Public Service and its customers should not have to give up one-half of the revenue stream that the property produces. In its HTY position the OCC adjusted the Company's cost of service to reflect the full amount of oil and gas royalties received by Public Service in 2008.

150. ACT also opposes the Settlement position and submits that Public Service has not justified retaining fifty percent of the oil and gas royalty revenues. Moreover, ACT argues crediting the cost of service with an amount reflecting historic or budgeted oil and gas revenues is not the most equitable way to account for these revenues. By using an historical or budgeted amount as a credit to the cost of service, ACT believes Public Service risks under collection while, on the other hand, the ratepayers are unfairly disadvantaged in the event that the amount collected by Public Service exceeds the amount credited to its cost of service. ACT recommends the full amount of oil and gas royalty revenues collected by Public Service be credited to the ECA.

151. We find that as part of the overall negotiated settlement package, the Settlement Agreement provides a reasonable resolution to this matter.

m. Employee Recognition

152. Staff initially opposed the inclusion of employee recognition expenses in the Company's revenue requirement and proposed a disallowance the full line item of $281,479, arguing these costs are not reasonable and necessary in providing electric service.

153. However, the Settlement included fifty percent of Staff's proposed disallowance, or $140,740, in the cost of service.

154. We reject the settlement position of partial disallowance for employee recognition expenses and authorize $281,479, the full amount initially requested by Public Service, to be included in the Company's revenue requirement.

n. Billing Determinants

155. The Settlement also notes that the billing determinants from the 2010 FTY be utilized in the Phase II rate design portion of this docket. These are the only billing determinants contained in the record of this case and we agree they should be used.

o. Healthcare Costs

156. The OCC proposes eliminating Public Service's increases to active employee healthcare costs over 2008 levels because they are not a known and measurable change in the Company's cost of service. The final healthcare costs will not be known until after year-end 2009.

157. The Company disagrees, arguing it used data from actual claims paid, estimated unpaid claims, and actuarial allocations to determine the test year cost of $30.2 million. This is an increase of $7 million over 2008 costs.

158. We find the Company's adjustment to be a typical business practice in light of healthcare accounting and deny the OCC's proposal to eliminate increases to healthcare costs above 2008 levels from the Company's cost of service.

p. Production Tax Deduction Rate

159. The FEA proposed an adjustment to the production tax deduction rate. The FEA states the rate should be increased to nine percent because that rate will be effective January 1, 2010, and represents a known and measureable change. The current rate of six percent will no longer be applicable.

160. We agree with FEA. In order to better reflect the actual amount of the production tax deduction we authorize the use of 9.0 percent in the calculation of the Company's production tax deduction portion of the revenue requirement.

q. Surcharge Proposals

161. Ms. Glustrom suggests the addition of two .05 percent surcharges on customers' bills. One surcharge would fund programs related to the process of phasing out coal plants including a study of long term coal supplies, communications with customers and employees, and a training fund for coal plant workers. The other surcharge would support increasing the OCC staff and provide a pool of money for ratepayers to participate in rate case dockets when they cannot afford to hire legal counsel or expert witnesses.

162. In its Rebuttal, Public Service does not support any additional surcharges, stating the existing coal studies can be relied on. The Company argues it and its customers already pay for quality representation by the OCC and *pro se* intervenor participation should not be funded by the Company or its customers. Public Service estimates each fund would generate between $1 million and $1.5 million annually.

163. We deny the proposal to create additional surcharges on customers' bills to fund these new programs. If Public Service decides to pursue work driven by the closing of coal plants, those are expenses that would be examined in the course of a rate case and if determined to be prudent would be given cost recovery.

r. Financial Analysis of Ms. Glustrom

164. Ms. Glustrom has raised a variety of issues that are similar to those she raised in Docket No. 08S-520E, the previous Public Service Phase I rate case. Her arguments concerning Comanche 3 are dealt with elsewhere in this order. More generally, Ms. Glustrom also argues

Public Service is a high earnings contributor to Xcel Energy, Inc. and that this Commission does not need to raise rates for Public Service.

165. Ms. Glustrom cites to a variety of 10-K reports for Xcel Energy, Inc. and its subsidiaries to perform a financial analysis over the recent past, from 2004 to 2008. She generally contends that Xcel Energy, Inc. is seeing increasing strength in earnings and Public Service is an increasingly strong source of earnings.

166. As we stated in Decision No. C09-0787 in Docket No. 08S-520E:

> Ms Glustrom requests that we amend the Commission Decision On Settlement to reflect the fact that the net income of Public Service went up by almost $100 million or about 40 percent between 2006 and 2008; that net income for Public Service's parent, Xcel Energy, Inc., went up by $74 million or about 13 percent between 2006 and 2008; that contributions of Public Service to the earnings of Xcel Energy, Inc., grew from about 41 percent in 2006 to about 52 percent in 2008 while the contributions by three other operating utility subsidiaries decreased over the same period of time. Ms. Glustrom questions whether there is an urgent need for Public Service to obtain a $112.2 million annual increase in revenue given that its ratepayers are already the largest contributors to the earnings of the parent company.
>
> We have reviewed the hearing testimony of Public Service Witness Mr. George Tyson1 and the evidence presented by Ms. Glustrom on this matter We find that the data relied on by Ms. Glustrom may be valuable in other contexts, but it is not is useful during ratemaking. We agree with Public Service that the issues raised by Ms. Glustrom are beyond the jurisdiction of the Commission and scope of this proceeding. Only the information related to those portions of Public Service's business that are regulated by this Commission is useful during ratemaking; however, the Securities and Exchange Commission also considers other aspects of the business, including interstate and unregulated operations as well as wholesale power business. Further, various costs incurred by Public Service are "below the line" for purposes of recovery in rates. We therefore deny the RRR filed by Ms. Glustrom on this issue.

167. While the exact vintage of the data cited by Ms. Glustrom might be updated in this case, the essential facts remain the same. Using data from financial reports that are not ratemaking financial reports is fatally flawed. By statute and rule, the ratemaking we perform is based on Colorado data that has been adjusted to remove Federal Energy Regulatory Commission activities and non-regulated financial information. Data in this rate case illustrates that Public Service was under earning in the period Ms. Glustrom used as her starting point, so the fact that Public Service has shown some rebound in earnings is not demonstrative. We therefore do not accept Ms. Glustrom's argument.

s. Bonavia Contract, Travel and Entertainment Expenses

168. The initial revenue requirement proposed by Public Service included cost recovery for several matters that were contested during these proceedings. These issues were ultimately addressed through adjustments to the proposed base rate revenue increase of $136,047,188 recommended in the Settlement Agreement. The adjustments are:

- Removal of the Bonavia employment contract expenses per Staff's recommendation ($955,982)
- Adjustment of food and beverage expenses per Staff's recommendation ($158,797)
- Removal of 2008 amounts associated with various sporting events and meals initially recommended by ACT ($121,000)[13]

169. These matters are included in the settled revenue deficiency amount and no party to this rate case opposed these reductions. We find that it is proper to exclude these items from the cost of service calculation.

[13] ACT brought these expenses to the attention of the Commission by offering Hearing Exhibit 124 on October 29, 2009, during its cross-examination of Public Service witness Ms. Blair. Exhibit 124 is Rebuttal Testimony prepared by John Lindell in a ratemaking proceeding before the Minnesota Public Utilities Commission on May 5, 2009. While that exhibit was ultimately excluded from the Record, Public Service did provide, at the Commission's request, an accounting of expenses similar to those identified in Exhibit 124.

t. Discount Increased Wholesale Sales

170. Mr. Eells argues Public Service's load forecasts from Docket No. 07A-447E are faulty and posits that Public Service does not need the generation facilities it is adding and requesting cost recovery for in this Docket. Mr. Eells argues customer demand is trending downward and the wholesale price of power is dramatically declining. He contends Public Service is attempting to raise rates on its regulated customer sector to overcome price drops in its wholesale business. Mr. Eells requests the Commission require Public Service to report monthly its wholesale power sales and the states to which its power is sold. Mr. Eells further requests the Commission require Public Service to discount rates charged to ratepayers if wholesale sales significantly increase over the near term.

171. We decline to adopt Mr. Eells' proposal. We understand that, because of lumpy investments, Public Service might have temporary excess capacity when it adds major facilities, especially in the midst of the greatest slowdown in economic activity, residential construction, and business creation in decades. We expect Public Service would be interested in selling excess power at prices that match or exceed its marginal cost. Therefore, temporary growth in that sector on the spot market would be prudent. We also note that Public Service's forecasted decline in wholesale power sales is partly determined by the shared venture in Comanche 3 with current wholesale customers.

4. Financial Impact to Customers

172. As is tradition with this Commission, public comments were invited via fax, e-mail, and other delivery means. In addition, the Commission held a formal Public Comment hearing. Thousands of faxes and e-mails were filed, objecting to a variety of the proposals by Public Service. Dozens of citizens spoke at the Public Hearing. Commenters expressed a

variety of concerns, but most of the concerns were raised regarding the size of the rate increase, the start-up of Comanche 3 and cost recovery for it, and a withdrawn tariff provision for net-metering customers with solar installations. So many citizens attended the Public Hearing that it was extended beyond the scheduled time.

173. We understand the interest in this case, both Phases I and II. The level of involvement in this case illustrates the public's strong desire to participate in the process of the Commission. Although institutions such as the OCC represent the interests of these consumers in front of the Commission, it is also important for us to have a direct connection to our many stakeholder groups. We appreciate the public's interest in this case and the commenters' candor in expressing their thoughts and concerns to us.

174. Several intervenors, notably Ms. Glustrom and ACT, spoke to the financially troubled times ratepayers are facing. It is understandable that ratepayers will want us to minimize the level of rate increases during this period. We, as a Commission, have a multi-faceted set of responsibilities in our work. We must ensure that rates are just and reasonable. However, we must also ensure that there is a reliable source of electricity because, if there is not, the results can range from mere annoyances to fatalities and catastrophes. It is true that Public Service needed to add significant amounts of generation, transmission, and distribution investment during an economically challenging period, but it is a given in the utility industry that investments are lumpy as opposed to other industries that can practice "just in time" methods of supply provision. Some of these investments were designed to have countervailing savings for consumers, such as reducing natural gas purchases and decreasing the need to purchase power from other suppliers.

175. In this rate case and Public Service's previous rate case, we have strived to balance a number of potentially conflicting concerns: minimizing the impact on consumers; ensuring the electricity stays on; providing for the financial health of Public Service; and pursuing a clean energy strategy. We will be examining a program to be established by Public Service for its low-income electricity customers in the next Phase of this rate case that will hopefully provide some level of protection to those in need. This will parallel a similar program we have previously approved for gas customers.

G. Smart Grid City

176. One of the contested issues in this proceeding is whether a Certificate of Public Convenience and Necessity (CPCN) should be required for the SmartGridCity project in Boulder, Colorado. The two related issues are whether SmartGridCity is in the ordinary course of business and whether it is distribution-related.

177. In its pre-filed testimony, Public Service contended that SmartGridCity does not require a CPCN because it is an investment in the distribution system. Ms. Karen Hyde testified that "SmartGridCity is a distribution project and does not include any transmission or generating capacity. Under Rule 3207,[14] construction or expansion of the distribution system is deemed to be in the ordinary course of business and does not require a CPCN."[15] In addition, Mr. Randy Huston testified that "to the extent the project ties to any particular portion of our system, it is distribution related…much of our SmartGridCity project consists of software, which is general plant, not generation or transmission plant. I would add that much of this project is

[14] Rule 3207(a) states that "[e]xpansion of distribution facilities, as authorized in § 40-5-101, C.R.S., is deemed to occur in the ordinary course of business and shall not require a certificate of public convenience and necessity."

[15] Rebuttal Testimony of Karen Hyde, p. 18, lines 1-10.

integrating intelligence (communication and software) into the distribution system."[16] During the hearing, Mr. Huston further testified that the software included as part of SmartGridCity does have some implications in the generation area.[17] Mr. Huston clarified that when he was testifying whether SmartGridCity is distribution related, he was doing so from a systems engineering perspective rather than from an accounting perspective.[18]

178. The Settlement Agreement proposes that Public Service not be required to obtain a CPCN for SmartGridCity. It would allow Public Service to amortize the 2009 O&M expenses of $2.8 million over a two year period beginning January 1, 2010. In addition, the settlement's HTY includes recovery of $42 million plant in service as of December 31, 2009, and forecasted 2010 O&M expenses of $4.1 million. The Settlement Agreement further provides that Public Service will file an application with the Commission prior to any deployment of comprehensive smart grid technology outside of SmartGridCity. In its Motion In Support Of Settlement Agreement, Public Service argued that (1) "despite the admittedly innovative nature of the project, the Company believes that [Rule 3207(a)] allowed the Company to proceed with SmartGridCity without a CPCN;" (2) that "it is not outside the ordinary course of business for the Company to test and deploy new technologies of all forms on its system;" (3) that this docket has given the parties adequate opportunity to explore cost overruns experienced by the Company and that these costs have been adequately explained; and (4) that SmartGridCity is almost complete and little would be accomplished in requiring Public Service to obtain a CPCN after the fact. For its part, Staff, in its Statement in Support of Settlement Agreement filed on

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[16] Rebuttal Testimony of Randy Huston, p. 15, lines 1-10.
[17] Transcript, October 30, 2009, p. 71, lines 14-15.
[18] *Id.*, p. 69, lines 21-22.

November 18, 2009, stated that the Settlement Agreement is responsive to its concerns regarding SmartGridCity.

179. The settlement represents a departure from Staff's position as presented in its pre-filed testimony. In its testimony, Staff argued that the Commission should require Public Service to obtain a CPCN for SmartGridCity because (1) although some elements of SmartGridCity are apparently part of the distribution system, other elements are not and the project as a whole spans several functional areas; and (2) SmartGridCity is not in the ordinary course of business because it is unique, largely untested, and many components of the project are not the typical equipment necessary in the provision of electric service in the ordinary course of business.[19] Staff further argued that the Commission should require a CPCN for policy reasons. First, ratepayers would benefit from a regulatory structure where costs are known and measurable. Further, a CPCN would allow the Commission to cap costs, monitor them in the future, and determine whether they are prudent and in the public interest. In addition, Staff argued that the ratepayers should benefit from intellectual property rights developed in the course of implementing the project.[20] Finally, Staff was unclear how much of the investment in SmartGridCity comes from ratepayers in rates versus contribution by shareholders.[21]

180. In addition, in its cross-examination of Ms. Hyde and Mr. Huston, Staff pointed out that SmartGridCity is different than most distribution systems in Colorado because (1) it enables customers to access energy use information; (2) it allows customers and the company to

[19] Answer Testimony of Harry DiDomenico, pp. 30-36.
[20] *Id.*
[21] *Id.*, p. 29.

control in-home energy management devices remotely; and (3) it may require laying of fiber next to existing distribution cables.[22]

181. The City of Boulder, the OCC, ACT, Ms. Glustrom[23] and Ms. Burchell argue a CPCN is required for SmartGridCity. In its testimony, Boulder argues that "the cost and magnitude of the proposed investment in SmartGridCity, coupled with its experimental character, are compelling reasons to require a CPCN."[24] In its SOP, Boulder contended that the assertions by Public Service that the project is distribution-related are not supported by evidence and that simply claiming that the project is not generation or transmission related does not make it distribution related. Boulder points out that because SmartGridCity will allow customers to adjust their energy consumption, an argument can be made that the project could also be related to generation plant since fewer plants will need to be built to accommodate demand for energy. In its SOP, Boulder further argues that SmartGridCity is not in the ordinary course of business because Public Service has partnered with private equity partners, which it probably would not do if it was simply expanding its distribution system. Boulder also argues that SmartGridCity is not in the ordinary course of business because intellectual property rights, which presumably are addressed in the agreements between Public Service and private equity partners, are not usually at issue in the agreements that Public Service enters into with contractors and subcontractors when expanding its distribution system.

[22] Transcript, October 26, 2009, pp. 129-130 and October 29, 2009, p. 178.

[23] In her cross-examination of Public Service's witness Mr. Huston, Ms. Glustrom offered Exhibit 136, a news article from the Associated Press entitled *Colo. Cities Receive $24.2 Million for Smart Grid*. Public Service objected to the admission of this Exhibit, arguing Mr. Huston was unfamiliar with the projects described in the article. The Commission agreed, and excluded Exhibit 136.

[24] Cross-Answer Testimony of Jonathan Koehn, p. 5, lines 6-7.

182. For its part, the OCC opines that SmartGridCity should not be included in HTY cost of service if in fact it was constructed in the ordinary course of business (unlike Comanche or Fort St. Vrain).

183. In its supplemental SOP, ACT takes issue with the provision in the Settlement Agreement that "Public Service will file an application outlining scope, technology and expected costs with the Commission prior to any deployment of comprehensive smart grid technology outside of SmartGridCity." It argues that the terms "application" and "comprehensive smart grid technology" are not well-defined. ACT also points out that this provision may allow further deployment of SmartGridCity technology *in* Boulder and could result in additional expenditures without prior Commission oversight. ACT also argues that SmartGridCity is not a "distribution facility" as that term is defined by the Commission's Rules and that meters are excluded from the definition of "distribution extension."[25] Finally, ACT argues that the Commission may not, via the Settlement Agreement, exempt Public Service from obtaining a CPCN for SmartGridCity.

184. Section 40-5-101(1), C.R.S., states that "[n]o public utility shall begin the construction of a new facility, plant, or system or of any extension of its facility, plant, or system without first having obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction." The statute does not require utilities to obtain a CPCN "for an extension within any city and county or city or town within which it has theretofore lawfully commenced operations, or for an extension into territory,

[25] Rule 3001(i) defines a distribution extension as "any construction of distribution facilities, including primary and secondary distribution lines, transformers, service laterals, and appurtenant facilities (except meters and meter installation facilities), necessary to supply service to one or more additional customers." Rule 3001(j) defines distribution facilities as "those lines designed to operate at the utility's distribution voltages in the area as defined in the utility's tariffs including substation transformers that transform electricity to a distribution voltage and also includes other equipment within a transforming substation which is not integral to the circuitry of the utility's transmission system."

either within or without a city and county or city or town, contiguous to its facility, line, plant, or system and not theretofore served by a public utility providing the same commodity or service, or for an extension within or to territory already served by it, necessary in the ordinary course of its business." *Id.* The Commission has discretion to award a CPCN retroactively, even if construction for a project has begun, if it determines, based on evidence in the record, that issuance of a CPCN will serve the public interest. *City of Boulder v. Pub. Utils. Comm'n*, 996 P.2d 1270, 1276 (Colo. 2000).

185. Previous Commission decisions identify several factors relevant in determining whether the project is in the ordinary course of business pursuant to § 40-5-101(1), C.R.S.: (1) whether it is necessary to serve load growth; (2) size, cost and magnitude of the project; (3) the presence of novel financing arrangements, which usually indicate that the project is not in the ordinary course of business; (4) whether the project from other distribution system expansions in the ordinary course of business to serve current and anticipated customers.[26] The Commission also previously stated that normal course of business includes only that which is routine, ordinarily-occurring, and usual for the business under review.[27] The Commission finally stated that the assessment of whether a project is in the ordinary course of business must be made on a case-by-case basis.[28]

[26] Decision No. R08-0925, at ¶¶28-23, affirmed by the Commission in Decision No. C09-0365 (discussing whether planned construction of certain natural gas pipeline laterals by Atmos Energy Corporation would be in the ordinary course of business). Decision No. R08-0925 was part of Docket No. 08F-033G, in which Public Service argued construction of the proposed gas pipeline laterals required a CPCN.

[27] Decision No. R05-1224 (discussing whether the sale of a substation and related facilities and equipment would be in the ordinary course of business).

[28] Decision No. C09-0365, ¶ 25.

186. We agree with Boulder and other interveners that a CPCN for SmartGridCity is necessary prior to cost recovery.[29] First, SmartGridCity is not in the ordinary course of business because of (a) its cost and magnitude ($42 million); (b) its uniqueness, including the fact that many of the technologies are being deployed for the first time; and (c) elaborate financing and intellectual property arrangements.

187. Second, we find SmartGridCity is not simply a distribution project. For example, Mr. DiDomenico testified that the project spans several functional areas and Mr. Houston testified that it has some implications in the generation area. We also agree with ACT that SmartGridCity does not fit neatly into the definition of "distribution facility" or "distribution extension" as these terms are defined by the Commission's Rules. The exemption pursuant to Rule 3207(a) therefore does not apply, at least in part, to SmartGridCity. Finally, any reliance on Rule 3207(a), to the extent that it applies *and* is inconsistent with or goes beyond the scope of § 40-5-101(1), C.R.S., is misplaced since a rule cannot contravene a statute.

188. We therefore find a CPCN is required by statute for SmartGridCity. Besides being required by law, the CPCN proceeding will allow the Commission to examine whether the costs incurred are prudent and in the public interest, and to monitor these costs in the future. We therefore order Public Service to file an application for a CPCN for SmartGridCity.

189. We are cognizant of the fact that SmartGridCity is the first project of its kind in the nation. We believe the smart grid concept holds great promise and we wish to encourage innovation and energy efficiency from the utilities we regulate. We prefer a forward-looking approach to address the situation at hand, even though we would have preferred Public Service to

[29] Commissioner Baker would not require a CPCN for SmartGridCity, believing the Commission could have satisfied its obligation to approve plant in service without a formal CPCN proceeding.

have filed its application for a CPCN for SmartGridCity earlier. For this reason, and without prejudging the merits of the CPCN proceeding, we will permit Public Service to recover the costs associated with the project pending the CPCN proceeding, subject to refund if the CPCN application is not granted.

190. We also intend to open a separate investigatory or miscellaneous docket to explore the issues related to performance of SmartGridCity as a pilot project, and to address such issues as the lessons learned, technical specifications and how SmartGridCity might progress from a pilot to system-wide implementation. We will issue a decision opening this docket in the near future, outlining in more detail the scope of issues we wish to examine. This docket may or may not proceed contemporaneously with the CPCN docket and we will balance the need to examine overlapping issues holistically, on one hand, and the need to issue an order in the CPCN docket in a timely manner and the need to remove regulatory uncertainty, on the other hand.

H. Future Rate Cases

1. Limitation on Future Filings

191. Parts of the Settlement lay out some guidance regarding the timing of the next rate case. The Settlement states:

> The Company agrees that it will not file its next electric retail base rate case filing until such case is needed to effect rate changes due to the expiration of the power sales agreement with Black Hills/Colorado Electric Utility Company, L.P. (currently anticipated to expire on December 31, 2011), provided that, the Company shall be entitled to seek relief by proposing an alternative mechanism to recover any potential incremental costs associated with the recent Resource Plan Order (Decision No. C09-1257) that would traditionally be recovered in base rates within this time frame or to recover unanticipated costs caused directly or indirectly by government action and resulting in material changes to the Company's expenses or investments.

Settlement Agreement, p.16.

192. This provision, commonly referred to as a “stay out” requirement, is meant to limit the Company’s ability to file a rate case for some period of time after new rates go into effect. Unfortunately this provision is relatively vague and allows Public Service discretion to file before the December 31, 2011 date in the provision. We find that this provision of the Settlement is too vague and we decline to adopt it.

I. Electric Commodity Adjustment

193. The Electric Commodity Adjustment (ECA) is a mechanism through with Public Service recovers fuel costs. Essentially, the ECA allows Public Service to pass those costs, with certain adjustments, directly through to the consumer. The current ECA was established in Decision No. C06-1379 and was set to expire when Comanche 3 goes into service, or December 31, 2009, whichever occurs first. Public Service and intervenors propose a number of changes to the ECA in this reauthorization.

1. Calculation Frequency

194. The current ECA is calculated and updated quarterly, as approved in Decision No. C06-1379. Public Service proposes increasing the frequency of ECA updates to a monthly calculation.

195. In support of this proposal, Public Service argues the quarterly ECA has inadequately incorporated changes in projected fuel and purchased energy costs. As a result, it claims very large deferred account balances (DABs) have accumulated from quarter to quarter. The Company currently uses DABs as a mechanism to true up its ECA cost recovery. In the simplest terms, the Company uses forecasts and modeling to make its best guess about what fuel costs will be in the coming quarter, and it submits these predictions quarterly to the Commission

in order to update its ECA. Because predictions are necessarily inexact, there is a high likelihood Public Service will over- or under-collect, depending on the difference between forecasted and actual fuel prices. This difference is incorporated as an offset to the next quarter's ECA. As an example, if Public Service significantly underestimates fuel costs, it would recover the resultant out of pocket expense, known as the DAB, by increasing its proposed ECA for the next quarter. If fuel prices are particularly volatile or modeling is exceedingly difficult, large DABs can accumulate as the Company waits to file an updated ECA.

196. Public Service argues that a monthly ECA would provide customers with more timely information about fuel prices and thus send a better price signal. Public Service witness Mr. Kundert testified about the differences to customers in utilizing a monthly mechanism as opposed to a quarterly mechanism. He argues the monthly mechanism allows the Company to better recover fuel costs from the customers who incur those costs. He therefore argues a monthly mechanism is truer to the regulatory principal of cost causation because it decreases customer to customer subsidies.

197. Staff opposes switching to a monthly ECA. Staff witness Mr. Davis argues a change to monthly ECA updates does not meaningfully improve its ability to send price signals. Mr. Davis testified that, in his opinion, Public Service's proposal was not reflective enough of marginal electricity production costs to send an efficient price signal.

198. The OCC is also opposed to the proposed change. The OCC believes quarterly ECA filings result in fewer mismatches between the start of a customer's cycle billing period and the start of a new ECA rate. The OCC also argues the ECA is ill equipped to act as a price signal because, in all likelihood, the majority of customers will learn of ECA price changes when they receive their bill, when it is too late to make behavioral changes which could have impacted that

billing cycle. In contrast, the OCC believes quarterly ECA updates may assist customers in making meaningful behavioral changes. The OCC also supports a quarterly ECA on the basis that it may reduce the volatility customers experience in their electricity bills.

199. Other intervenors represent an interesting mix of business perspectives. WalMart and Copper Mountain represent opposing views. WalMart supports a monthly ECA, because it prefers an ECA that reflects the most recent costs incurred by Public Service. Copper Mountain, on the other hand, finds having a three month locked in price very valuable from a planning perspective. CEC essentially mirrors the position of Staff and the OCC on this issue.

200. We find that Public Service's arguments in support of a monthly ECA are not persuasive. In deliberations, the Commission noted cost adjustment mechanisms like the ECA initially developed as a way for a utility to collect costs outside its control. For a variety of reasons, the Commission questions the wisdom of attempting to use the ECA to send price signals.

201. While the quarterly ECA does not perfectly match cost incurrence with cost causation, the Commission notes that, due to the ECA's function as a true-up mechanism, both customers and the utility are made whole on an annual basis.

202. To address Public Service's concerns about large DABs under a quarterly filing, the Commission will allow the Company to make interim ECA filings if it determines DABs are growing too large within the quarterly period. The Commission wishes to note, however, that the use of interim filings is intended to be the exception, rather than the rule. With this allowance for interim filings, the Commission believes quarterly ECA filings are preferable.

2. Time of Use ECA Rates

203. Public Service proposes implementing Time of Use (TOU) ECA rates. It argues TOU ECA rates would further improve the ECA's ability to serve as a price signal. Currently, a customer pays the same ECA cost for each unit of fuel, regardless of whether that consumption occurs on- or off-peak. Generally, more expensive generation is used to meet the incremental on-peak needs of customers. Public Service believes a mandatory TOU ECA rate would more fairly recover costs from the customers creating them, and would encourage customers to shift usage to off-peak periods.

204. However, Public Service is currently incapable of charging all customers time-differentiated ECA rates. The customer's meter must be able to record when the energy is used, and there are additional data-collection and processing requirements. Therefore, Public Service proposes implementing TOU ECA rates only for customers taking service at transmission and primary delivery voltages because these customers have Integrated Digital Recording (IDR) meters, which record both contribution to peak demand and the time when energy is used, information Public Services needs to bill customers TOU Rates. If TOU ECA rates are adopted, Public Service proposes defining on-peak hours as 9:00 a.m. to 9:00 p.m. non-holiday weekdays. Public Service would charge 33 percent more for energy consumed during the on-peak period under this proposal.

205. Public Service recommends differentiating between on-peak and off-peak charges by conducting load research to determine, by customer class, the on-peak to off-peak load ratio. This would allow for the estimation of on-peak and off-peak usage by class. The Company will then weight sales by the resulting price ratios.

206. No parties opposed this proposal. However, Staff suggested the Commission establish a greater differentiation between on-peak and off-peak rates to encourage reduction in on-peak usage.

207. The Commission finds Public Service will be able to accurately and appropriately implement TOU ECA rates for customers with IDR meters. The Commission further believes the differentiation between on- and off-peak charges, as proposed by Public Service, is appropriate and creates a distinction significant enough to impact customer behavior. The Commission will therefore adopt Public Service's proposal for TOU ECA rates.

3. Class Specific ECA Rates

208. Public Service proposes instituting a class-specific ECA for the following rate classes: residential, small commercial, secondary general, primary general, transmission general, and lighting. The existing ECA mechanism charges all customers at a given voltage level the same rate. Public Service believes this approach does not reflect that a kWh of energy consumed during the peak period is more costly to provide than energy consumed during the off-peak period.

209. However, Public Service is currently unable to measure each individual customer's on- and off-peak consumption due to metering limitations. Until it becomes cost-effective to provide all customers with meters that can measure time-of-use consumption, Public Service suggests developing class-specific ECA rates using projected hourly usage by class and projected hourly marginal costs. Public Service claims this proposed rate design would better match rates with cost-causation. In other words, Public Service believes class specific ECA rates better reflect its cost to serve each class.

210. Staff opposes class differentiated ECA rates. Staff is not convinced the proposed allocation method results in rates that truly signal marginal costs. Staff believes the insufficient similarity in the load factors among customers in the same rate class cuts against class specific allocations of ECA revenue requirements. To put it another way, there is so much diversity in the customer load factors that the allocation of ECA costs should not be done on a customer class basis. Staff also points out that the allocation of ECA costs to rate classes seems, on its face, to discourage smart metering and dynamic rates. Staff finds it difficult to reconcile the Commission adopting a cost allocation approach for ratemaking premised on the uniformity of usage patterns among residential customers at a time when there is national momentum towards the deployment of more sophisticated metering that precisely measures each residential customer's on- and off-peak consumption.

211. CF&I Steel and WalMart generally support Public Service's class differentiated ECA proposal. CF&I Steel witness Mr. Baron stated he believes allocation of ECA costs through Public Service's proposed mechanism would allow it to more accurately track fuel cost associated with seasonal load characteristics.

212. For a variety of reasons, the Commission will not accept the cost allocation change proposed by the Company. First, we are not convinced this proposal adequately reflects actual cost causation at the class level. The Commission is troubled by the proposal to allocate ECA related costs on a marginal cost basis and not on an actual cost of service basis. While Public Service can claim a relationship between on- and off-peak allocators to customer class usage patterns, there are other factors to consider in allocating cost to a specific class. Further, this proposed method, contribution to peak, is just one such method, and is not usually employed

to allocate energy costs. There are potentially several other marginal cost allocators that could be proposed; one is not necessarily superior to others.

213. Second, we are not convinced this proposal adequately reflects actual cost causation at the customer level. A uniform rate for a customer class, as proposed by Public Service, will be based on customer class load patterns rather than specific customer characteristics. A customer would see essentially no benefit in reducing peak usage if the rest of the class does not follow suit. To some extent this problem – the connection of a single customer to the entire class – exists for all elements of cost allocation. But when cost allocation is employed explicitly to try to shape customer behavior, as in this case, the problem is more acute. In this case, we prefer that the class-level allocation continue to be based on the average actual cost of the classes.

214. Finally, even if the issue of relationship of the individual customer to the class is ignored, we note that the resulting cost shifts are quite small and would not likely send the price signals Public Service claims support this proposal. Therefore, we will keep the current cost allocation and rate structure within the ECA mechanism in place and not implement class specific ECA rate design at this time.

4. Sulfur Dioxide Allowances

215. Public Service sold sulfur dioxide (SO2) allowances in 2006 and 2007, and returned to customers the retail share of the margins associated with those sales through the ECA. In October 2008, it requested this mechanism become a permanent component of the ECA tariff. Public Service's proposed tariff sheets in this filing incorporate an SO2 allowance component into the ECA. Public Service seeks to incorporate the SO2 margins from the previous calendar year in the filing made for ECA rates effective April 1, 2010, and to credit the

ECA for the following year. This mechanism is similar to that proposed for the sharing of short-term wholesale electric margins.

216. Staff finds the tariff language proposed by Public Service to be consistent with the decision issued in Docket No. 08A-274E and recommends that the Commission approve the inclusion.

217. We agree that the proposed tariff language including margins from the sale of SO2 allowances is consistent with our previous decisions and therefore approve it as a permanent part of the ECA.

5. Sales Margins Sharing and the Economic Purchase Benefit

218. Public Service makes discretionary short-term energy sales from its generating assets into wholesale energy markets. There are two types of sales at issue in this case. The first, known as Generation Book, or Gen Book, occurs when Public Service sells its excess production into the wholesale market. The second, Proprietary Book, or Prop Book, are trading sales, in which the Company is buying and selling energy on the market.

219. Under the current system of Gen Book sales, the Company retains 20 percent of the margins of such sales after it reaches a threshold amount designed to compensate it for Administrative and General (A&G) costs associated with its trading activities that are not recovered in base rates. The remaining 80 percent of these margins are shared with customers through inclusion in the ECA. If losses on these transactions result in negative margins in a year, Public Service, not its customers, bears those losses. Currently this threshold trigger is set at 50 percent of A&G expenses.

220. The ratio is inverted for Prop Book sales. After the threshold is met, Public Service keeps 80 percent of Prop Book margins, and provides 20 percent to customers through an ECA credit.

221. Public Service proposes to alter this formula for sharing short term sales margins. Prior to the instant filing, the Company was tracking A&G costs for Prop and Gen Book together. However, the Company's trading department is now tracking A&G costs for Prop and Gen Book separately, and it wishes to modify the 50 percent threshold to reflect the separate values for each of these activities. Public Service projects the 2010 threshold for Gen Book will be $266,048 and Prop Book will be $614,049, for a total of $880,097.

222. All intervenors addressing this topic focused their testimony on the sharing that occurs between customers and the Company in Gen Book and Prop Book operations. Staff Witness Podein opposes continuing to provide Public Service an incentive for system sales unless it can be shown that sufficient margins exist to mitigate the environmental impact from those sales. Ms. Podein argues that, unless Public Service can demonstrate the margins are sufficient to fund measures offsetting the increased emissions, sharing should be discontinued as contrary to Governor Ritter's Climate Action Plan. Ms. Podein believes the cost of carbon must be considered as part of electric production expense and that trading profits must be sufficient to mitigate the environmental impact produced by excess generation.

223. The OCC argues Public Service's electricity trading operations have sufficiently matured such that they no longer require such generous sharing percentages to the utility. In other words, the OCC believes Public Service's Gen Book trading operations have become part of its ordinary course of business and should therefore no longer be so heavily incentivized. Therefore, the OCC proposes changing the Gen Book sharing percentage to 95 percent to

customers and five percent to Public Service. The OCC further recommends Prop Book sharing percentages mirror, but in a reciprocal manner, whatever sharing percentages the Commission adopts for Gen Book. That is, if the Commission adopts its proposed 95 percent to customers and five percent to Public Service for Gen Book margins, then the Prop Book margins should be shared 5 percent to customers and 95 percent to the Company. The OCC also wants A&G expenses related to Gen Book to be removed from ECA calculations and be placed in base rates.

224. CEC believes customers should retain 100 percent of the net margins from Gen Book and allow Public Service to retain 100 percent of the net margins from Prop Book. CEC argues Public Service's operation of its trading division and the sharing mechanisms it has in place are no longer necessary and should now be considered standard utility practice.

225. In her rebuttal testimony, Public Service witness Ms. Hyde offers to eliminate the Economic Purchase Benefit (EPB) incentive if it is allowed to keep the sharing percentages between customers and shareholders as they currently exist. The EPB incentivizes the Company to maximize wholesale economic purchases in order to lower its operating costs. Currently, the EPB includes a threshold level of purchases. Below that threshold, customers retain 100 percent of the savings from wholesale purchases. Above the threshold, savings are shared 80 percent to customers and 20 percent to the Company.

226. We view this proposal offered by Ms. Hyde as a reasonable compromise between all the parties regarding this incentive mechanism. We also find that at this time the market on carbon trading has not matured enough to progress with Staff's proposal to impute a cost of carbon into the margins that Public Service recognizes from its short term trading operations. However, the Commission may consider such a proposal at a future date.

227. Further, we believe the existing sharing mechanisms for Gen Book and Prop Book transactions give Public Service a proper level of incentive to engage in more energy trades that are well beyond the hourly economic transactions most utilities limit themselves to. Further, we believe these transactions benefit customers. The co-mingling of Gen Book and Prop Book trading has allowed Public Service to leverage its position in short term trading for the benefit of customers, as well as shareholders, and the current percentages for sharing these margins reflect an appropriate level incentive sharing between these two groups. Only the OCC discussed the original proposal put forward by Public Service Witness Kundert regarding the proposed changes to the dollar amounts it needs to recover for A&G expenses before sharing can begin.

228. We find that the threshold methodology proposed by Public Service is appropriate. We therefore order that 50 percent of Public Service's A&G cost related to trading operations be the recovery threshold before sharing begins. We further order that the current 80 percent customer – 20 percent Company sharing percentage for Gen Book margins and 20 percent customer – 80 percent Company Prop Book margins be maintained and that the EPB incentive be eliminated. We reiterate that rate payers are not responsible for any losses the Company realizes as a result of these trading programs, and nothing in our approval of these sharing mechanisms is meant to imply otherwise.

6. Base Load Energy Benefit

229. The Base Load Energy Benefit (BLEB) was created to provide and incentive to the Company to improve the operating performance of its base load coal facilities. The Company believes the BLEB is no longer aligned with regulatory and environmental goals. As such, it proposes eliminating this incentive. No party opposes eliminating the BLEB. We agree

that the BLEB is out of sync with this Commission's regulatory priorities. As such, we will order the BLEB be discontinued.

7. Wind Integration Incentive

230. In place of the BLEB, the Company proposes creation of a new incentive, the Wind Integration Incentive (WII). Public Service argues the WII would encourage it to increase the accuracy of its wind projections and therefore reduce its integration costs attributable to wind output uncertainty.

231. Public Service estimates an 18 percent error rate between actual and projected wind production. For 2010, it estimates this forecasting error will impose about $17 million of additional integration costs than would have been the case if wind generation could be perfectly forecast. Public Service has contracted with the National Center for Atmospheric Research (UCAR) for a Wind forecasting tool known as Wind Predictor (WiP). Public Service projects the WiP will reduce the wind forecasting error by 2 percent in 2010, to 16 percent. Public Service proposes temporarily sharing any savings it is able to achieve from reducing the wind forecasting error above and beyond the reductions it expects to obtain through the use of the WiP tool.

232. A number of parties oppose the creation of the WII. Staff argues the value added by any possible refinements to UCAR's model or increased weather training for its personnel is unknown at this time. With regard to the WII, Staff believes Public Service's proposal fails to distinguish between reductions in wind forecast error achieved by Public Services as opposed to UCAR. However, Staff would consider a future filing for an incentive akin to the WII at such time when sufficient historical data exists to support a measurable performance standard.

233. The OCC believes that, to the extent that Public Service is able to more accurately forecast the wind above and beyond the error forecasting reductions that it expects to obtain

through the use of the WiP forecasting tool, Public Service seeks to retain a portion of the savings. The OCC recommends that the comparative baseline upon which to measure annual improvements be based on the prior year's wind forecasting error percentage and not the average of the two prior year's wind forecasting error percentage.

234. CEC believes Public Service should not be awarded another incentive program for doing what it believes is a utility's normal business practice. It also believes Public Service's calculation of the WII was very convoluted and hard to understand.

235. CF&I Steel – Climax stated that it believes Public Service should not be awarded another incentive program for doing what it believes is a utility's normal business practice. It further believes that Public Service is trying to create an incentive for improvements that are not brought about by efficient operations and just simply add to its shareholder returns.

236. Interwest reiterated in its Statement of Position that it believes the current incentive mechanisms related to the ECA are enough, and that the Commission should not approve the WII. One of its primary issues is that they believe Public Service is not setting the bar high enough in this area to qualify for an incentive. They find Public Service's standard of a day-ahead error rate of 18 percent to be too high for industry standards. Interwest wants the Commission to order a comprehensive study of wind integration on Public Service's system involving investigation of entering into multi-state agreements to bring about regional cooperation in wind integration.

237. We agree with the several positions brought forward by the Commission Staff and various intervenors that the WII is not needed. We commend Public Service for researching methods to improve accuracy of wind prediction as it looks to reduce integration costs of this resource onto its system. We find that, in light of the current national discussion, improving the

integration of renewable resources into a utility's energy portfolio is within the ordinary course of business. Therefore, we need not create another incentive for this activity.

238. We also note the wind prediction technologies are relatively new and the robust standards that would come from longer periods of experimentation have not yet been developed to a point where incentives could be based upon showing solid improvements. We are compelled by Interwest's witness Mr. Cox that the industry standards that do seem to exist in this area appear to indicate that Public Service may in fact be setting the bar for improvement too low.

239. The Commission is not opposed to considering incentives in the future for exceptional performance in the area of wind integration.

8. Fuel Additive Pilot Program

240. Public Service seeks recovery of costs associated with use of a fuel additive it claims lowers fuel costs by improving a coal unit's heat rate. Public Service provided testimony that described the method by which the additive and its beneficial impacts on slag and clinkers, and how the additive is designed to lower maintenance costs. It had been used on a trial basis at Comanche 1 in 2004 and was found to lower maintenance costs by more than the cost of the additive. Public Service now proposes to use it at four coal plants as part of a pilot program. It believes the ECA is the proper cost recovery mechanism because the use of the additive is directly related to fuel costs and the ECA allows better cost tracking and recovery of the expense.

241. Ms. Glustrom argues that, due to the similarity of this additive to other fuel sources, the Commission should require Public Service to first utilize the additive at a single plant and then report back results before the additive is allowed to be used at other generation plants. Ms. Glustrom also suggests the Commission preclude cost recovery for fuel additives until Public Service does a study on mine-specific coal supplies.

242. No other parties intervened to oppose this program.

243. We see no reason to deny Public Service cost recovery for the fuel additive. Public Service has demonstrated sufficiently that the use of the additive has shown net positive benefits from an engineering and financial perspective. We are not convinced by Ms. Glustrom that this cost recovery should be denied.

9. Proposed Rulemaking

244. Staff recommends the Commission initiate a rulemaking to establish a process by which utilities could change ECA rates on a less-than-statutory notice basis. Staff considers it poor policy to not have a more formal review process for costs that make up such large part of Public Service's revenue requirement.

245. We acknowledge Staff's suggestion to institute a rulemaking procedure to address these issues in the ECA. We note that there are ongoing efforts being made by an internal working group at the Commission tasked with exploring many of these issues. The expectation is that this working group will present Public Service's findings to the Commission at some near future date.

246. For these reasons, we do not order a new, separate rulemaking procedure at this time but we acknowledge the Staff suggestion and look forward to a report on the efforts of this internal working group.

10. **Proposed Investigatory Docket**

247. Staff recommends opening an investigatory docket to explore various incentives that could be used to steer Public Service's ECA related activities toward furthering policy objectives and the goals of the Governor, State Assembly and the Commission. Staff believes the Commission has an opportunity to take a fresh look at the ECA and to put its own stamp on its

design rather simply continuing or updating what has been approved in the past. Staff feels this is especially true in the case of incentive mechanisms. Staff believes Public Service's current proposals are not well aligned with current policies and priorities at a local, state and national level.

248. We believe that an existing investigatory docket, Docket No. 08I-113EG, opened by this Commission on March 26, 2008, can serve as a vehicle to address Staff's concerns regarding incentives and how they are utilized in the ECA. Because Docket No. 08I-113EG remains open, we decline to open another investigatory docket at this time. We encourage Staff to raise these issues in Docket No. 08I-113EG.

11. Fuel Cost Sharing

249. Ms. Glustrom makes two proposals. First, Ms. Glustrom requests that Public Service bear 10 percent of fossil fuel costs. In the alternative, she proposes the Company absorb all fossil fuel costs that are more than 20 percent above projections. ACT similarly recommends the Commission consider limiting the percentage of fuel costs Public Service may recover through the ECA.

250. Public Service claims it has prudently planned its generation system to include a mix of resources, which are all needed now to meet its load. It further argues that, although some intervenors are opposed to fossil fuels, particularly coal, it should not be penalized for utilizing those resources. Public Service argues these fossil fuel resources will be used to generate electricity for customers and that customers should appropriately bear the costs of fuel needed to operate those units. Public Service contends fuel costs are largely outside of its control. Public Service characterizes these disallowances as a penalty for having its present mix of generation resources.

251. Cost recovery mechanisms like the ECA were not designed to **ensure** complete recovery of any cost merely related to fuel. There should not be an assumption on the part of a utility that simply because it can make a link between a cost item and fuel, recovery of a cost is automatic in the ECA/GCA mechanisms.

252. We agree with Mr. Sanzillo that changing national markets or political landscapes are likely to impact utilities' future fuel choices. The Commission is prepared to address resource plan proposals in light of these developments. As stated earlier, these discussions are best suited for future planning dockets and even in investigatory dockets on incentive mechanisms, but not in the current case.

253. We therefore find that the current cost-sharing mechanisms should be maintained for all fuel sources currently utilized by Public Service to meet its load requirements.

12. ECA Terminology

254. Ms. Glustrom asserts rate payers will be better informed if fossil fuel costs are split out of the ECA. She further proposes that the ECA should be renamed the Fossil Fuel Cost Rider. In addition, she proposes informing ratepayers what part of the Fossil Fuel Cost Rider is for coal costs and what part is for natural gas costs. She asserts that a simple line discussing greenhouse gas emissions associated with coal and natural gas will allow rate payers to determine the "carbon footprint" associated with their consumption.

255. In light on on-going state and national discussions regarding the impacts of carbon upon the environment, we feel utilities should strive to give customers as much information as practical on their energy use and potential environmental impacts. We highly encourage Public Service to explore practical venues where this type of information would be available to customers. We are issuing no directives in this area at this time, but imagine that if

Public Service finds inclusion of this information on a customer's bill is not practical, there may be alternative methods of communication such as, for example, Public Service's website. We leave these detailed decisions to Public Service but reaffirm our support for providing more information to customers who seek it.

256. We therefore order that the current naming convention for this rider, the Electric Commodity Adjustment, be maintained. We also encourage Public Service to design ways to practically convey information on carbon emissions related to customer usage and the fuel-mix currently utilized to those who desire it.

II. ORDER

A. The Commission Orders That:

1. The first argument presented in the Joint Motion *in Limine* filed by Wal-Mart Stores, Inc., Sam's West, Inc. and the Colorado Department of Transportation is denied. Public service shall, however, modify in future filings its advice letter text and customer notice text in accordance with our discussion above. The other arguments presented in the Joint Motion *In Limine* will be dealt with in conjunction with our analysis of the Phase II issues.

2. Public Service Company of Colorado (Public Service) is authorized to file appropriate tariff sheets reflecting a revenue requirement increase of $66,954,536, representing the identified revenue requirement of $128,318,889, less $61,364,353 for Comanche 3. Comanche 3 costs will be incorporated into rates consistent with the above discussion.

3. The Settlement Agreement entered into by Public Service, Staff of the Commission, Colorado Energy Consumers and Energy Outreach Colorado on November 18, 2009, is approved, in part, consistent with the modifications discussed above.

4. Public Service shall file an application for a certificate of public convenience and necessity (CPCN) for SmartGridCity consistent with the above discussion. Public Service shall make this application no later than 30 days from the Mailed Date of this Order. As described above, in the event the CPCN application is not granted, a refund shall be ordered that removes the costs associated with the project from rates.

5. The Electric Commodity adjustment is modified in accordance with the discussion above. Public Service shall make its next ECA filing consistent with this discussion.

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

7. This Order is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETINGS December 1, 3, and 22, 2009.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

RONALD J. BINZ

JAMES K. TARPEY

MATT BAKER

Commissioners

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