Decision No. C05-0049

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 04A-214E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2003 LEAST-COST RESOURCE PLAN.

DOCKET NO. 04A-215E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER APPROVING A REGULATORY PLAN TO SUPPORT THE COMPANY'S 2003 LEAST-COST RESOURCE PLAN.

DOCKET NO. 04A-216E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE COMANCHE UNIT 3 GENERATION FACILITY.

ORDER APPROVING SETTLEMENT

Mailed Date: January 21, 2005
Adopted Date: December 17, 2004

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I. BY THE COMMISSION

A. Statement

1. On April 30, 2004, Public Service Company of Colorado (Public Service or Company) filed an application for approval of its Least Cost Resource Plan (LCP). On that same date, Public Service also initiated Docket Nos. 04A-215E and 04A-216E, by filing applications for approval of a regulatory plan to support the LCP and for a certificate of public convenience and necessity (CPCN) to construct a 750 MW coal-fired, base load power plant known as Comanche 3.

2. The Commission's Electric Least-Cost Resource Planning Rules, 4 Code of Colorado Regulations (CCR) 723-3-3600 through 3615, require jurisdictional electric utilities to

file a least-cost resource plan on or before October 31, 2003[1], and every four years thereafter. In addition to the four-year cycle, a utility may file an interim plan. Each investor-owned electric utility is required to file a LCP that includes:

a) a statement of the utility-specified resource acquisition period and planning period;

b) an annual electric demand and energy forecast developed pursuant to rule 3606;

c) an evaluation of existing resources developed pursuant to rule 3607;

d) an assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3608;

e) an assessment of need for additional resources developed pursuant to rule 3609;

f) a description of the utility's plan for acquiring these resources pursuant to rule 3610; the proposed Requests for Proposals (RFPs) the utility intends to use to solicit bids for the resources to be acquired through a competitive acquisition process; and

g) an explanation stating whether the current rate designs for each major customer class are consistent with the contents of its plan. The utility shall also explain whether possible future changes in rate design will facilitate its proposed resource planning and resource acquisition goals.

3. According to Public Service's LCP, it was imperative that several issues be addressed concerning the energy needs of its customers. First, Public Service indicates that it has a need for approximately 3,600 MW of generation resources over the next ten years, which is equivalent to approximately one-half of its current total capacity. This 3,600 MW of resource need stems from its projected load growth over the next ten years which will require the Company to either procure or build approximately 2,000 MW of new generation. Additionally, Public Service will need to either renegotiate or replace another 1,600 MW of existing capacity

[1] The variance in the dates is explained by Decision No. C03-1224, mailed on October 30, 2003 in Docket No. 03V-416E, where we granted Public Service's Verified Petition for a Variance in the Filing Date of its Electric Least-Cost Resource Plan.

under purchased power contracts that will expire during the LCP resource acquisition period, which extends from 2003 through 2013.

4. Public Service's LCP also included construction of Comanche 3 of which the Company proposes to own approximately 500 MW of the 750 MW this new coal-fired base load plant will generate. Public Service proposes to construct Comanche 3 at its existing generation site in Pueblo, Colorado. The estimated construction cost of the project as of January 2004 was approximately $1.149 billion. Public Service estimated that the completed project costs, assuming an in-service date of October, 2009 would be within plus or minus 20 percent of the $1.149 billion estimate.[2] As proposed Comanche 3 would use a combustion technology known as "supercritical pulverized coal technology," which, according to Public Service, will provide a lower emissions rate and lower life cycle costs, as well as a faster start-up duration of any pulverized coal-fired technology currently commercially available. According to the LCP, this proposal will ultimately result in lower costs than could be achieved by developing the plant at a new or "green-field" site. Public Service also proposes to utilize a low water use cooling technology and emission control technology.

5. The LCP also indicated the need to re-balance Public Service's resource portfolio and fuel diversity by adding new coal-fired generation and pursuing additional wind generation. Public Service maintained that in the last ten years, its system generation fuel mix had gone from 6 percent natural gas based in 1995 to 48 percent natural gas based in 2004. Public Service argued that this fuel mix left the Company susceptible to volatile natural gas prices.

[2] As represented in Attachment D, the in-service date for Comanche 3 will be during 2010.

6. To help re-balance its resource portfolio, Public Service requested approval of the Comanche 3 plant as well as the addition of 500 megawatts of new wind generation. Public Service contends that incorporation of such generation resources will create energy cost savings for its customers. Further, the Company sought an expedited acquisition of additional wind generation so that it could be added to its system prior to the expiration of federal production tax credits. Public Service also requested early approval of a renewable energy Request for Proposals (RFP) so that it could pursue additional wind generation on a fast track.

7. Regarding the acquisition of base-load generation through construction of Comanche 3, Public Service maintains that because of high capital costs, siting issues, permitting risks and long development and construction lead times, it is doubtful whether any Independent Power Producer (IPP) could successfully develop a new base-load coal generation facility. Public Service argues that it could construct Comanche 3 at least two years earlier than coal generation could be obtained through a competitive acquisition process. According to the Company's calculation this could result in savings approaching $100 million on a present value basis.

8. As part of its LCP, Public Service indicates that it has re-assessed its demand forecasting process and examined the weather factors that affect its summer peak demand and resource planning requirements. As a result of modeling of demand variability, transmission import capacity, and generation availability, Public Service requests use of a higher planning reserve margin than what was historically used, of seventeen percent. The Company maintains that use of a higher planning reserve margin would increase the amount of new supply and demand side resources it would need to acquire over the next ten years.

9. Public Service also indicates in its LCP that it currently purchases 48 percent of its electric generation capacity resources from IPPs and other utilities. In its testimony included with the application, Public Service expresses concern that credit rating agencies such as Standard & Poors (S&P) and Wall Street analysts are increasingly considering a portion of the Company's fixed contract obligations to be the imputed equivalent of company debt. Public Service represents that construction of Comanche 3 as a new rate base plant will partially mitigate its increasing imputed debt associated with its purchased power obligations. According to the Company this should help to maintain its financial integrity and contribute to lower electricity rates for customers in the future. Further, Public Service argues because the debt markets look to a utility's balance sheet for loan security it needs a strong balance sheet whether it builds generation itself or buys it from IPPs.

B. Procedural History

10. As originally filed, Public Service maintained that in order to develop and implement its LCP strategy, it needed Commission approval of the LCP, including its application for a CPCN for Comanche 3, and for an LCP rate adjustment rider, which it filed concurrently in these consolidated dockets. It also requested approval of a waiver from Commission LCP Rule 3610(b), the 250 MW limitation, to allow Public Service to own approximately 500 MW of Comanche 3. Public Service additionally requests Commission recognition of the impact purchased power contracts have on its credit rating, which would include approval of its proposed use of an equity adjustment factor in the evaluation of power purchase alternatives.

11. Within the original LCP application Public Service also sought approval of a Renewable Energy RFP by July 15, 2004 in order to allow it to initiate the process of acquiring additional renewable resources to take advantage of the federal production tax credits. It also

sought approval of its LCP by October 2004 so that it could release its All-Source RFP in October 2004, which would allow Public Service to initiate the process of acquiring resources for 2007 through 2013. Under an alternative proposal, the Company suggested that in the event a Commission decision had not been reached on the LCP by October 2004, Public Service requested Commission authorization to release the All-Source RFP by October 1, 2004 in order to meet the resource need identified in the 2007-2009 timeframe. Under this alternative, upon a Commission decision on the LCP, in particular a grant of the Comanche 3 CPCN, Public Service indicated it would initiate solicitation of resources needed for the 2010-2013 timeframe.

12. On May 25, 2004, Public Service filed a motion for expedited approval of the Renewable Energy RFP with the suggestion of a hearing date the week of July 5, 2004 and the approval of the Renewable Energy RFP by July 15, 2004. The Company further requested that we authorize the issuance of a possible bifurcated All-Source RFP by October 1, 2004. Public Service also asked that we consolidate the LCP docket with Docket Nos. 04A-215E and 04A-216E, even though it did not pre-file testimony in the LCP Docket, while it did pre-file testimony in the other two dockets.

13. Because we found unusual Public Service's requests for an expedited Commission ruling on one or two aspects of a docket, while the remainder of the case proceeded on a non-expedited schedule, we found it necessary for Public Service to clarify its request by providing additional information. As a result, in Decision No. C04-0548, issued May 26, 2004 we posed several questions to Public Service to clarify the legality of the Commission entering a ruling upon portions of an application prior to a ruling on the entire application, as well as its proposal to expedite select portions of the LCP Docket. That decision also allowed parties who requested intervention in these matters to respond to Public Service's filing; set a prehearing conference for

June 18, 2004; and tentatively scheduled a hearing on July 7, 2004 to expedite consideration of this matter in Docket No. 04A-214E. We did note that depending on whether Public Service's RFP request was opposed, the number of opponents, and the scope of the issued to be addressed, the July 7, 2004 hearing date may prove overly ambitious.

14. On June 11, 2004, Public Service filed a motion to expand the issues to be addressed at the June 18, 2004 prehearing conference. However, in Decision No. C04-0654, issued June 16, 2004, we found that Public Service's motion was not timely and consequently denied the motion.

15. On June 16, 2004, we issued Decision Nos. C04-0655 and C04-0656 in Docket Nos. 04A-215E and 04A-216E respectively regarding response time to the numerous interventions filed in these dockets. In order to allow for timely consideration of Public Service's application, we shortened response time to petitions for intervention to noon on June 21, 2004, for those specific petitions for intervention for which response time had not expired.

16. At the June 18, 2004 prehearing conference, we considered the interventions to Docket No. 04A-214E. Interventions to this docket were filed by Colorado Governor's Office of Energy Management and Conservation; Holy Cross Energy; Colorado Renewable Energy Society; Tri-State Generation and Transmission Association, Inc.; City and County of Denver; Western Resource Advocates (WRA); City of Boulder; Sun Power, Inc.; North American Power Group, Ltd.; Arkansas River Power Authority; Rocky Mountain Farmers Union; Colorado Mining Association; Environment Colorado; Calpine Corporation (Calpine); LS Power Associates, L.P.; Climax Molybdenum Company and CF&I Steel, LP; Regents of University of Colorado-Boulder; Baca Green Energy, LLC and Prairie Wind Energy, LLC; Colorado Energy Consumers Group; Southwest Energy Efficiency Project; Colorado Coalition for New Energy

Technologies; Colorado Independent Energy Association (CIEA); PacifiCorp; and Ms. Leslie Glustrom. The interventions by Staff of the Public Utilities Commission (Staff) and the Colorado Office of Consumer Counsel (OCC) were also addressed.

17. We waived response time to the petitions for intervention and allowed oral response. We received no oral responses and consequently granted all petitions for intervention in Docket Nos. 04A-214E except for the petition filed by Ms. Leslie Glustrom. We denied Ms. Glustrom's petition to intervene since it did not meet the "substantial interest" required by our rules for intervenor status. We noted that the OCC is statutorily charged to represent residential customer interests from a rate perspective, therefore Ms. Glustrom's interests were adequately protected by OCC's intervention.

18. At the June 18, 2004 prehearing conference, we also considered Public Service's motion for expedited approval of the Renewable Energy RFP and a procedural schedule which would accommodate that expedited approval, as well as ruled on the interventions to Docket No. 04A-214E. We concluded that it was necessary to create a separate docket in order to expedite the RFP and order an administratively final decision.[3] Based on our findings, we granted Public Service's motion for expedited approval and opened Docket No. 04A-325E. Since all of the parties who were granted intervenor status in Docket No. 04A-214E expressed an interest in being intervenors in this new docket, we granted them all intervenor status in Docket No. 04A-325E. We placed the following documents from Docket No. 04A-214E into the record of Docket No. 04A-325E: Volume 2 of 4 of Public Service's 2003 LCP, as amended by the direct testimony of Mr. James Hill; a copy of the LCP application filed by Public Service; and the supplement to

[3] *See* Decision No. C04-0738 in Docket No. 04A-214E and Decision No. C04-0739 in Docket No. 04A-325E, issued July 6, 2004.

the application filed on June 4, 2004. We further determined that the scope of Docket No. 04A-325E was governed by LCP Rules 3600-3615. We therefore limited all testimony to issues that related only to the LCP Rules and set a hearing date of August 4, 2004 in Docket No. 04A-325E.

19. On June 22, 2004, we ruled on the petitions to intervene in Docket Nos. 04A-215E and 04A-216E; the amended petition to intervene of Ms. Leslie Glustrom in Docket Nos. 04A-214E, 04A-215E and 04A-216E; motions to consolidate Docket Nos. 04A-214E, 04A-215E and 04A-216E filed by Public Service; a request for the Commission to rule on Public Service's motion for waiver of the 250 MW limit in Rule 3610(b) as a preliminary matter filed by the CIEA; and motion to dismiss Docket No. 04A-216E field by CIEA.[4]

20. Petitions to intervene in Docket No. 04A-215E were filed by the Colorado Governor's Office of Energy Management and Conservation; Holy Cross Energy; Colorado Renewable Energy Society; City and County of Denver; WRA; City of Boulder; North American Power Group, Ltd.; Colorado Mining Association; Environment Colorado; Calpine ; LS Power Associates, L.P.; Climax Molybdenum Company and CF&I Steel, LP; Regents of University of Colorado-Boulder; Baca Green Energy, LLC and Prairie Wind Energy, LLC; Colorado Energy Consumers Group; Southwest Energy Efficiency Project; Colorado Coalition for New Energy Technologies; Ms. Leslie Glustrom; and CIEA.

21. Petitions to intervene in Docket No. 04A-216E were filed by Colorado Governor's Office of Energy Management and Conservation; Holy Cross Energy; Colorado Renewable Energy Society; City and County of Denver; WRA; City of Boulder;

[4] *See* Decision No. C04-0710.

North American Power Group, Ltd.; Arkansas River Power Authority; Aquila, Inc.; Colorado Mining Association; Environment Colorado; Calpine; LS Power Associates, L.P.; Climax Molybdenum Company and CF&I Steel LP; Regents of University of Colorado-Boulder; Baca Green Energy, LLC and Prairie Wind Energy, LLC; Colorado Energy Consumers Group; Southwest Energy Efficiency Project; Colorado Coalition for New Energy Technologies; Ms. Leslie Glustrom; and CIEA.

22. No responses to the interventions were filed. We granted all petitions for intervention except for Ms. Glustrom as discussed previously. Staff and the OCC filed notices of interventions in these two dockets as well.

23. Several intervenors raised arguments regarding consolidation of the three dockets. Those arguments centered around four themes: 1) The application filed in Docket No. 04A-216E was not complete under the Commission's Rule 55, Rules of Practice and Procedure; 2) the waiver request of Public Service for LCP Rule 3610(b) had not been granted and it is premature to consolidate these dockets; 3) the issues in Docket Nos. 04A-215E and 04A-216E were not similar to the issues in Docket No. 04A-214E; and 4) consolidation would harm the overarching competitive acquisition concept of the LCP Rules, resulting in prejudice to the parties. Staff did not oppose consolidation and stated that while the issues were similar, they had concerns with the impact of consolidation on the merits of Public Service's motion for rule waiver. Staff recommended that, if the Commission granted the consolidation request, the Commission should make it clear that such a decision has no effect on the merits of the motion for waiver of the 250 MW limit in Rule 3610(b).

24. CIEA did not oppose consolidation of Docket No. 04A-214E with Docket No. 04A-215E, but it did move to dismiss Docket No. 04A-216E, or requested that we hold a

hearing on the motion for waiver of the 250 MW limit in Rule 3610(b) and decide on the issue before ruling on consolidation. WRA recommended that we consolidate Docket No. 04A-214E with Docket No. 04A-216E, but we should not include Docket No. 04A-215E in the consolidated case.

25. In Decision No. C04-0710, we disagreed with the intervenors that argued that the application in Docket No. 04A-216E was not complete because no financial information was provided as required by Rule 4 CCR 723-1-55(c)(5), or because the application did not include tariffs as required by Rule 55(c)(6). Rather, we found that since this was a facilities CPCN application, those two rules were not applicable. Consequently, we deemed the application complete at our June 16, 2004 Commissioners' Weekly Meeting.

26. We also disagreed with the arguments regarding a waiver of the 250 MW limit in LCP Rule 3610(b). We found that we could hold a hearing on the merits of the motion for waiver at the same time that we heard the merits of the overall LCP in Docket No 04A-214E. We also found that consolidation of the dockets would result in administrative efficiency because the issues in the three dockets were interrelated and did not constitute a ruling on the merits of the waiver request.

27. We also found that no harm would result by consolidation of the dockets, especially to the overarching competitive acquisition concept of the LCP Rules. We found that no prejudice would inure to any party through consolidation. As such we consolidated Docket Nos. 04A-214E, 04A-215E, and 04A-216E. We denied CIEA's request that we preliminarily rule on Public Service's motion for waiver of the 250 MW limit in Rule 3610(b) before hearing the remainder of the case. We also denied CIEA's motion to dismiss Docket No. 04A-216E. We scheduled a prehearing conference for the consolidated dockets for July 8, 2004.

28. We held a prehearing conference at the appointed date and time to set procedures for hearing dates, filing deadlines and associated requirements. As a result of that prehearing conference, we issued Decision No. C04-0836 on July 22, 2004, that set hearings on the three dockets for November 1, 2004 to continue as necessary through November 19, 2004. We also set public hearings for September 23, 2004 in Pueblo, Colorado and for September 27, 2004 in Denver, Colorado. We set the procedural schedule for the parties to file supplemental and answer testimony. Finally, we agreed with CIEA that additional issues should be included within the scope of this case. Public Service agreed to file testimony to include: 1) the ground rules for bidding the proposed Comanche 3 coal plant; 2) compliance with utility bidding requirements contained in Rule 3610(e); and 3) how to fairly evaluate Public Service's rate-based plant against a competitively bid plant.

29. On September 3, 2004, we issued Decision No. C04-1052 which granted several motions including Yampa Valley Electric Association, Inc.'s Petition for Leave to Intervene. We granted the petition on the condition that it take the case in these dockets as they exist on the date of the Order. We also approved the locations for the public comment hearing procured by Public Service.

30. In Decision No. C04-1201, issued October 14, 2004, we ordered all parties to provide their witness lists, estimates of cross-examination, and their preference as to whether it would be more efficient to designate certain hearing days for specific issues by October 22, 2004. We also ordered Public Service to file the completed summary of cross-examination by witness, by party, and it total for the case. Additionally, we required all pre-filed testimony and exhibits to be identified and marked prior to the 9:00 a.m. hearing commencement on November 1, 2004.

31. In Decision No. C04-1282, issued October 27, 2004, we addressed Public Service's Motion to Strike Cross-Answer Testimonies of several witnesses for intervenors. The testimonies Public Service sought to strike fell into two general categories. First, it sought to strike testimony from intervenors which was filed in response to Staff's request for additional answer testimony in the form of cross-answer testimony soliciting comment to Public Service's argument that the All-Source solicitation would not likely result in competitive firm-priced coal bids. Second, Public Service sought to strike testimony which it characterized as merely bolsterism of the other parties' answer testimony or which was testimony that should have been filed within the deadline for filing answer testimony.

32. We granted Public Service's motion with regard to the testimony filed in response to Staff's solicitation for comment regarding the All-Source solicitation. We found that the cross-answer testimony at issue should have been filed as answer testimony, which deadline had since passed. As for the second group of testimonies, we determined, pursuant to 4 CCR 723-1-81(b)(1) that testimony that addressed issues from Public Service's direct case, or that was cumulative or merely supported the findings of other parties' witnesses should be excluded for lack of probative value. However, when we found that the cross-answer testimony in question did possess probative value, we determined that it was reasonable to allow it, despite the fact that it may not have been usually admissible under the Colorado Rules of Evidence.

33. Hearings on the three consolidated dockets began at the appointed time and date on November 1, 2004. However, prior to the commencement of the hearing on November 18, 2004, counsel for Public Service represented to the Commission that parties to the consolidated dockets had reached a settlement in principle regarding the matters at issue. As such, Public Service requested that the remainder of the hearing be stayed pending submission to the

Commission of a proposed settlement agreement reduced to a written document. At that time, it was not clear as to which parties were a part of the settlement agreement, or which issues were settled as part of the agreement. By Decision No. C04-1409, we stayed the proceedings pending submission of the settlement agreement. We also set a hearing on the settlement of December 8 and 9, 2004. Public Service filed the settlement agreement on December 3, 2004, along with a motion for approval of the settlement.

34. In order to expedite the settlement agreement hearing, we submitted a list of questions to the parties to the settlement in Decision No. C04-1441. We ordered the parties to be prepared to answer the questions we propounded at the settlement hearing. We additionally set a public hearing on the settlement agreement for December 8, 2004 in Decision No. C04-1428, issued December 3, 2004.

35. Hearings for the settlement agreement were conducted on the appointed date and time. However, because a large number of the parties to the docket, who were not signatories to the Settlement, didn't enter appearances at the settlement hearing and because of the short response time to Public Service's motion for approval of the settlement, we solicited all parties to the docket to offer statements of their respective positions regarding the settlement. We ordered them to file on or before December 15, 2004, a statement indicating whether they support, oppose (and whether the party intended to contest the settlement), or take no position on the proposed Settlement.

II. SETTLEMENT

A. Summary of the Settlement

36. The Parties indicate that the Settlement provides a comprehensive resolution to all issues raised in Docket Nos. 04A-214E, 04A-215E, and 04A-216E. If we approve the

Settlement as proposed, we will be granting specific approvals for a number of aspects of these dockets. Our approval of the Settlement will also invoke numerous commitments made by the Parties in this docket, in future Commission dockets, and in proceedings before other jurisdictions. The significant points and commitments proposed in the Settlement are described in the following summary.[5]

37. The Stipulation between Public Service and the Concerned Environmental and Community Parties (CECP Stipulation) is attached to the Settlement as Attachment A. In addition to approving the Settlement, the Parties seek specific Commission approval of Sections 3, 4, 5, 6, 7, 8, 12, 14, and 15 of the CECP Settlement as part of the Commission's order. Theses sections of the CECP address the following areas: Section 3 – Emission Limits for Sulfur Dioxide Emissions; Section 4 – Emission limits for Oxides of Nitrogen; Section 5 – Limits for Particulate Matter; Section 6 – Installation and Compliance Schedule; Section 7 – Monitoring, Testing and Emission Limits for Mercury; Section 8 – Other Air Permits; Section 12 – Carbon Dioxide Proxy Cost; Section 14 – Energy Efficiency; and Section 15 Renewable Energy. Section 17(A) of the CECP Settlement states that, if the Commission does not approve in full the Company undertaking the commitments in these sections of the CECP Settlement, or if a Commission order significantly impedes implementation of any of the commitments under the CECP Settlement, or if the Commission Order approving such commitments is reversed on judicial appeal in any significant respect, Public Service's and CECP's obligations under the CECP Settlement are terminated . By approving the Settlement, we would effectively trigger the

[5] Included with this order are the Settlement (the Comprehensive Settlement Agreement), Attachment A to the Settlement (the CECP Settlement), Attachment D to the Settlement (the Computer Modeling Analysis of the Propose LCP Settlement), and the signatory page. Not included with this order are Attachments B and C to the Settlement because they contain highly confidential information relating to the possible ownership share of the Comanche 3 plant with Intermountain Rural Electric Association and Holy Cross and the construction cost cap.

CECP Stipulation requirements by authorizing Public Service to implement these provisions. The CECP Stipulation contains specific environmental requirements and City of Pueblo area civic accommodations, as discussed below. The CECP Stipulation also requires Public Service to take actions to pursue innovative generation technologies in the future. These actions include legislative support and solicitation of federal funding for generation projects that reduce carbon emissions. In return, the signatories to the CECP Stipulation agree not to contest Commission approval or the air permit process for Comanche 3.

38. In reaching our decision to approve the Sections of the CECP Settlement, we are guided by our statutory obligations pursuant to §40-2-123, C.R.S. to give "the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in [our] consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protections and insulation from fuel price increases." We are also guided by the mandates of §40-3-111(1.5)(a), C.R.S. which states "[i]f the commission considers environmental effects when comparing the costs and benefits of potential utility resources, it shall also make findings and give due consideration to the effect that acquiring such resources will have on the state's economy and employment…" Additionally we are persuaded by the fact that competing environmental interests were able to arrive at such a comprehensive set of environmental measures which allow Public Service to achieve the goals it sought in its LCP, and provide a benefit not only to its ratepayers[6], but to all citizens of Colorado in the form of cleaner air.

[6] According to the Company's calculations, an earlier in-service date for Comanche 3 would save ratepayers millions of dollars.

39. We find it is within our jurisdiction and authority pursuant to §40-2-123 and §40-3-111(1.5)(a), C.R.S. to approve the Sections of the CECP Settlement. We note that the General Assembly has seen fit to endow the Commission with the authority to provide for funding mechanisms to encourage Colorado's public utilities to reduce emission or air pollutants as a matter of statewide concern. *See,* §40-3.2-101, C.R.S. Therefore given our statutory mandate regarding the environmental portions of the Settlement Agreement, we find that because these Sections of the CECP Settlement are an integral part of the overall Settlement Agreement and the ratepayers derive benefit from them, they should be approved.

40. As indicated above, by approving the Settlement, we would approve several aspects of these dockets. These include: approval of Public Service's application for a CPCN for Comanche 3; its request to construct and own the full 750 MW of the Comanche 3 plant; and approval to a transfer of up to 250 MW of Comanche 3 ownership to Intermountain Rural Electric Association (IREA) and/or Holy Cross, pursuant to the terms in confidential Attachment B. A separate application would be required to transfer ownership to parties other than IREA or Holy Cross, or under terms other than those specified in Attachment B. We would also grant a waiver of the 250 MW limit in Rule 3610(b), as requested by Public Service.

41. In approving the Settlement and in turn the portions of the CECP Settlement mentioned above we would approve the SO_2 and NOx emissions controls for Comanche 1 & 2 as outlined in Public Service's Rebuttal testimony, and add lime spray dryers for Comanche 1. These emission controls are to ensure that Comanche emissions meet the specifications contained in the CECP Stipulation. We would also approve the mercury provisions in the CECP Stipulation. Under this provision, Public Service will test the mercury levels of the Comanche units, and the Colorado Department of Public Health and Environment (DOH) will use the

results to determine mercury emission limits for each of the Comanche units. These mercury emission controls would have an initial annual operating cost of $2 million to $5 million, beginning no later than two years after initial start-up of Comanche 3. The Parties represent that these mercury controls will likely be a sorbent injection system.

42. The Settlement also specifies that the Commission will deem these environmental controls expenditures to be prudent and their costs will be recoverable in rates. Likewise, we would approve the Operation & Maintenance expenses for these emissions controls as recoverable in rates to the extent they are prudently incurred. Although the CECP Stipulation requires Public Service to contribute funds to reduce air emissions associated with mercury from car body recycling and diesel exhaust from Pueblo school buses, the Settlement clarifies that these costs are not recoverable in rates.

43. Approval of the Settlement would also include approval of a construction cost cap on the amount of Comanche 3 costs that are recoverable from ratepayers. The level of this cap would be determined at a later date in accordance with confidential Attachment C. The construction cost cap would generally be determined based on the bids that Public Service receives for the various components of Comanche 3, and updates to other cost parameters. The Settlement clarifies that the Parties can challenge the recovery of replacement power costs resulting from imprudent delays, even if costs for Comanche 3 are below the construction cost cap. Public Service agrees to a requirement to file semi-annual Comanche construction progress reports beginning June 1, 2005, and ending with the first report after Comanche 3 reaches commercial operation, which is expected to be in 2010.

44. The Settlement also calls for approval of a sixteen percent planning reserve margin for the 2003 LCP. Public Service agrees to perform a probabilistic reserve margin study.

The results of this study would be used to set the reserve margin in Public Service's next LCP. Public Service also agrees to perform transmission studies for Comanche 3 as suggested by Staff witness Dominquez in his Answer testimony.

45. The Settlement specifies several modifications to the All-Source bid evaluation modeling parameters proposed by Public Service in its application and Rebuttal testimony. Specifically, Public Service will not apply a balance sheet equalization factor to bids for an imputed debt adjustment. For bid evaluation purposes Public Service would use CO_2 costs of $9.00/ton beginning in 2010 and escalating at two and one-half percent per year. Public Service will apply a Renewable Energy Credit (REC) value of $8.75/MWh for all renewable resources bid into the All-Source solicitation.

46. The Settlement provides that when assessing supplier concentration and parent company financial strength of bidders, the evaluation will focus on an assessment of the bidder's ability to perform the obligations of the project under a potential purchase power agreement. Public Service would not eliminate bids solely on the amount of generation provided by one supplier. Public Service will also remove the ten percent excess capacity allowance term from the model contract.

47. The Settlement additionally provides for up to fifteen percent wind penetration rate in the All-Source solicitation if that resource is selected as part of the least-cost portfolio, using the ancillary costs determined through the cost study required in Docket No. 04A-325E. Public Service would expedite this ancillary cost study in order to use it for the All-Source bid selection. If Public Service achieves a ~~fifteen~~ [ten] percent wind penetration rate, it would perform a second study of ancillary costs at a twenty percent penetration rate which may be used in the next LCP proceeding. In approving the Settlement we would approve a ten percent

capacity value for wind resources based on the nameplate capacity of the wind facility. Public Service agrees to complete a wind capacity study based on Effective Load Carrying Capability (ELCC) by November 1, 2006, and agrees to consider reliability contribution in all hours of the year in assessing the capacity value of wind resources for its next LCP. Public Service would also request permission from wind resource developers to disclose their historic data to other Parties.

48. Public Service would also be required to implement up to 320 MW of cost-effective demand reduction under a Demand Side Management (DSM) program, up to a maximum cost of $196 million. This proposed DSM program is discussed in detail below. As the part of the Settlement Public Service agrees to file an application for additional DSM resources within three months after the DSM market study is complete, but not later than July 1, 2006. Public Service also agrees to support a DSM working group which shall meet at least twice a year. Though the Parties state that they are not sure that a waiver is required to implement the DSM specified in the Settlement, they nonetheless advocate granting a waiver for the DSM if required.

49. With respect to Public Service's regulatory plan application, the Settlement specifies that a LCP rate adjustment rider will not be used to recover Comanche 3 financing costs. However, the Settlement does provide for the recovery of Comanche 3 costs through future rate case proceedings before the facility is placed in service, as discussed in detail further below.

50. As part of the justification for approving the Settlement, Public Service witness Hill modeled the Settlement scenario and compared the results with Public Service's Rebuttal case scenarios and the generic screening scenarios. Those scenario analyses are contained in

Attachment D. They show a Net Present Value (NPV) revenue reduction of $90 million when compared with the Company's Rebuttal case scenarios, and between $500 million and $1.3 billion reduction when compared to the generic screening scenario. The NPV rate impacts of the Settlement scenario shows a slight increase of approximately $0.05/MWh ($0.00005/kWh) when compared to the Rebuttal case and a reduction between $0.58 and 2.14/MWh compared to the generic screening case.

B. Discussion of the Settlement:

51. The Parties assert that when taken as a whole, the Settlement provides benefits that are greater than could be achieved in any position advocated by a single party. As is common in any stipulation proposed to the Commission, the Parties advocate that we approve the Settlement without any modifications. However, the Commission has often modified specific terms of stipulations in the past in order to protect the public interest. We find it most expedient to use the following procedures to determine whether to approve or deny the Settlement, or approve it with modifications.

52. We first consider whether the overall benefits achieved by the Settlement are greater than could be achieved through a fully litigated proceeding. In making this decision we look to whether the benefits of the Settlement outweigh the additional costs to ratepayers imposed in the Settlement. The costs of the Settlement are largely the additional environmental controls on Comanche 1&2; the level of DSM proposed to be evaluated under the Total Resource Cost (TRC) test, which may increase rates to consumers; and whether the REC and CO_2 modeling costs agreed to by the Parties could result in the selection of higher cost resources. The benefits to ratepayers include a more expedient approval of the Comanche 3 CPCN application and air permit, implementation of the Comanche 3 construction cost cap, and

postponement of the collection of Comanche 3 financing costs to future rate cases. We next consider whether to modify specific terms of the Settlement, by eliminating terms that we find not to be in the public interest, or to achieve a better overall balance of terms.

C. CPCN and Air Permit Delay

53. Several intervenors contested the approval of Comanche 3 based on environmental concerns. Those intervenors generally advocated that the Commission deny the approval of Comanche 3 (including the waiver from the LCP bid4ding rules), or require Public Service to change the technology to an Integrated Gasification Combined Cycle plant (IGCC), which would significantly reduce air emissions.

54. Public Service responded that IGCC technology is unproven on a commercial scale, particularly with western coal. According to Public Service, an IGCC plant would not provide the cost benefits or the reliability of a pulverized coal plant.

55. One of the most significant benefits derived from the Settlement is the agreement by environmental groups and Pueblo community groups not to oppose the approval of Comanche 3 or its air permit. This concession was obtained through an exchange of environmental conditions on Comanche units and different resource selection terms from that which Public Service initially proposed. In its Comanche 3 CPCN application, Public Service proposed additional emission controls on the existing two Comanche units so that the net regulated emissions at the Comanche site would be reduced. Public Service believed this would allow an expedited air permit process for Comanche 3. Public Service maintained that one of the primary cost savings of Comanche 3 would be the early in-service date created from the expedited air permit process.

56. As part of the Settlement, Public Service agrees to additional controls on the Comanche units to provide a net reduction in SO_2 and NO_x emissions after Comanche 3 is installed. It would also reduce mercury emissions from the Comanche units and in other locations in Pueblo.

57. The Parties further agree not to contest the pre-construction air permit or operating permit for Comanche 3. In addition to the intervenors in these consolidated dockets, several other entities agreed to these terms by signing the CECP Stipulation. These entities include Better Pueblo, Diocese of Pueblo, Smart Growth Advocates, Sierra Club, and Environmental Defense. Though these entities are not intervenors in this consolidated docket, it is important that they are signatories to the CECP Stipulation. With these additional groups, the Settlement includes the primary environmental and Pueblo area community groups. The Settlement thus reduces the risk that construction of Comanche 3 will be delayed by further litigation.

58. Public Service states that the air permit approval timing can have a very large impact on the expected benefits of Comanche 3. While the Parties recognize that groups outside this docket can contest the air permit, they argue that approval of the Settlement should help to mitigate air permit delays.

D. Approval of Comanche 3 with a Construction Cost Cap

59. In its application Public Service proposed to construct Comanche 3 as a rate-based facility, with all prudently incurred costs recoverable from ratepayers. Public Service provided detailed cost estimates for Comanche 3, which it characterized to be within the accuracy of plus or minus 20 percent. However, Public Service requested approval to construct

Comanche 3 without a limit on the level of recoverable costs—even if the prudently incurred actual costs exceeded its estimate by more than 20 percent.

60. In its Answer testimony, Staff did not take a position on whether the Commission should approve Comanche 3, but instead recommended that the Commission impose a construction cost cap if it did approve the plant. The OCC also recommended that the Commission approve Comanche 3, but only with a construction cost cap. The OCC recommended that the actual dollar value of the cap be established in a separate docket in the future.

61. In Rebuttal testimony, Public Service argued that it would be improper for the Commission to disallow prudently incurred costs for a rate-based plant. Further, Public Service represented that its cost estimates did not include any contingency amounts necessary to cover the risk of future cost increases. As such, Public Service stated that it would not be fair to limit the Company to a regulated return on actual costs, while placing it at risk for prudently incurred costs that exceed a capped amount. Public Service pointed out that many factors such as the price of steel, cost of capital, and inflation are not within its control and could impact its ability to maintain costs within a capped amount.

62. The Parties propose in the Settlement that the Commission approve Comanche 3 with a construction cost cap, although the actual amount of the cap is not specified. Rather, the Parties propose to use a formula-based method to establish the level of the construction cost cap. This cap will be based on the future bid prices of certain major components of Comanche 3 and will be adjusted based on other factors. The Settlement specifies the details of the construction cost cap calculation in confidential Attachment C.

63. The Settlement proposes that the Commission approve Comanche 3 before establishing a final construction cost cap amount. There could be the possibility that Comanche 3 would be built within a cap that is higher than costs analyzed in this case. In accordance with the Settlement, neither the Parties nor the Commission would be able to re-evaluate whether Comanche 3 is still a least-cost resource at the time the level of the cap is determined. That is, if the bids for the Comanche 3 components come-in higher than anticipated, the construction cost cap will still allow Public Service to recover these higher costs, through the application of the formula method which would adjust the cap accordingly, without a subsequent review of the cost-effectiveness of the project.

64. We find that Public Service has adequately demonstrated that Comanche 3 will provide savings compared to other base load generation options. Because Comanche 3 is a "brownfield" expansion of an existing coal plant, the common use of existing coal handling, rail, and general site facilities provide many cost savings when compared to greenfield options. In addition to these cost savings, there are potential savings in operation and maintenance costs from the combined Comanche operations. Another advantage of Comanche 3 is the potential for it to be operational one to two years before a greenfield coal plant. This earlier in-service date for Comanche 3 is projected to save ratepayers hundreds of millions of dollars.

65. We find that the formula approach proposed in the Settlement provides a reasonable method to establish the amount of the construction cost cap. The potential costs of delaying the approval of Comanche 3 until the construction cost cap price is known outweigh the risks of the construction cost cap price being substantially higher than is currently anticipated. The cost savings associated with the brownfield Comanche 3 unit warrant approval before the construction cost cap is finalized.

66. The Comanche 3 construction cost cap provides a reasonable means of ensuring that runaway Comanche 3 costs are not imposed on ratepayers. The construction cost cap limits ratepayer exposure, and provides incentives for Public Service to properly manage the project. We find the construction of Comanche 3, with a formula-based cost cap, will likely provide significant cost savings to ratepayers

E. Demand Side Management (DSM)

67. In its original application Public Service did not propose any company-sponsored DSM. Instead Public Service proposed to solicit DSM bids as a part of its All-Source RFP, and accept only those bids that were selected as part of the least-cost portfolio based on NPV rate impact analysis, consistent with Commission Rules.

68. Several intervenors recommended that Public Service implement company-sponsored DSM programs. Intervenors further recommended that the Commission direct Public Service to use the Total Resource Cost (TRC) test instead of the Net Present Value (NPV) rate impact test to evaluate these DSM programs. The intervenors argued that the utility is in the best position to implement DSM, and a bid-only DSM program would be inadequate. They also asserted that the NPV rate impact test unnecessarily restricts DSM and that the TRC test is an industry standard which must be used in order to properly evaluate the cost-effectiveness of DSM programs.

69. In its Rebuttal testimony, Public Service proposed a total of 150 MW of DSM, including company-sponsored DSM evaluated under the TRC test. DSM bids would still be solicited and would be evaluated under the NPV rate impact test. Public Service proposed that any DSM bids it accepted would reduce the amount of company-sponsored DSM.

70. In the Settlement, the Parties propose 320 MW of cost-effective DSM, up to a maximum cost of $196 million. The Company will target 40 MW of DSM per year for eight years. This $196 million maximum cost includes $2 million for an initial DSM market study and $2 million for ongoing study and measurement/verification of the DSM that is implemented. Public Service will use its best efforts to implement 40 MW (and 100 GWh) of cost-effective DSM per year, up to a maximum level of 320 MW (and 800 GWh) between January 1, 2006 and December 31, 2013. This 320 MW level will be reduced, if necessary, to limit the total cost to $196 million, or if less than 320 MW can be implemented on a cost-effective basis. In the event that the 320 MW level is achieved at a cost lower than $196 million, Public Service will nevertheless limit the DSM to 320 MW. According to the Settlement, the Company will strive to implement programs that give all classes of customers an opportunity to participate. Additionally, Public Service will hire up to 18 full-time employees, in addition to current staff, to implement the program. The cost for these additional employees, as well as other labor costs for the expanded DSM, are included within the $196 million limit.

71. Public Service agrees to use the TRC test to determine the cost-effectiveness of the company-sponsored DSM programs. Costs for these DSM programs will be recovered through the existing DSMCA cost adjustment mechanism with an 8-year amortization period. Public Service will report specific DSM parameters within its annual DSMCA filing. The Parties agree that Public Service may make an out-of-period adjustment in its 2006 rate case for DSM labor up to 18 full-time equivalent employees and other related costs. These costs will not be recovered through the DSMCA.

72. We have several observations regarding the proposed company-sponsored DSM program. Rule 3610(f) requires the utility to select its final resource plan with the primary

objective to minimize the NPV of rate impacts. While the TRC test would minimize utility costs, rates may nonetheless increase compared to a scenario where the utility implements generation resources instead of the DSM. This is because the TRC test maintains the same utility cost as with the avoided generation. But this cost would be spread over reduced levels of demand and energy due to the DSM demand and energy savings. DSM implemented under the TRC test may increase rates more than the generation it avoids. The small number of ratepayers who participate in the DSM program will see their individual utility bills reduced, however, all other customers' rates will increase.

73. We are also concerned that customers in lower economic brackets are not likely to participate in the DSM programs, and will be affected by DSM rate increases. For example, some customers may not be able to afford to invest in long-term energy savings equipment. However, because the Settlement Agreement strives to make available to all customers the ability to participate in a DSM program, each rate class and the customers within each class should be able to benefit.[7]

74. While we recognize that the DSM provisions will contribute to a five cent increase in the average present value rate on a dollar per MWh basis, we note that the Settlement Agreement results in the lowest cost resource plan.[8] Further, the expenditures for the DSM provisions are capped at $196 million (in 2005 dollars).

75. Although we are concerned about the DSM proposal, we find it important to consider it in light of the overall benefits derived in the Settlement Agreement. We find that the

[7] *See* Direct Examination of Mr. Fredric Stoffel, Hearing Transcript, Vol. 14, December 8, 2004, page 36, line 20 to page 37, line 7.

[8] These values are shown on page 12 of Attachment D by comparing the Rebuttal Scenario 1 to the Settlement Scenario.

Settlement Agreement , when taken as a whole, including the DSM provisions, is in the public interest.

F. CO_2 Cost

76. In its original application Public Service performed screening runs with several different levels of CO_2 emissions cost. These included no cost, $6 per ton, and $12 per ton of CO_2 emissions.

77. Several intervenors advocated for higher CO_2 costs to be applied in resource selection modeling. For example, WRA recommended $12 per ton base case and $40 per ton for a high end. OCC and Calpine advocated $12 per ton CO_2 emissions cost. The intervenors generally argued that it is a question more of when rather than if this greenhouse gas will be regulated. According to the intervenors, CO_2 mitigation requirements would likely be implemented through Federal legislation. This could be accomplished through a carbon tax, a program to cap CO_2 emissions and allow trading, or some other type of program that ultimately imposes a cost on CO_2 emissions.

78. In Rebuttal testimony Public Service proposed to include a CO_2 cost of $6.00 per ton for resource modeling purposes, beginning in the year 2010. Public Service agreed that some future CO_2 emissions cost is likely, but disagreed with the magnitude of the cost recommended by other intervenors. The Company argued that any CO_2 emissions cost will likely include a limiting mechanism, to prevent CO_2 costs from significantly disrupting the U.S. economy.

79. The Settlement proposes to add a $9.00 per ton CO_2 emissions cost beginning in 2010, including a two and one-half percent annual escalation factor. It is important to note here the use of the term “carbon tax” was freely used throughout this proceeding by the Parties. We

take this opportunity to point out that it is not a tax in the true sense of the word. Instead that term refers to a "carbon cost adder" which will be used by Public Service in its initial screening and in the running of its optimization model for resource selection purposes. It is not a fee that will be collected from ratepayers or paid to a governmental body. Additionally should there come a time in the future when a carbon tax or other CO_2 cost is imposed, based on the testimony of Mr. Plunk, we believe it will likely be imposed on the owner of the generator by the Federal government. It is also important to note that we agree to the $9.00 per ton carbon cost adder as part of this Settlement Agreement only. Our approval of the carbon cost adder should not be construed as precedent regarding future Commission decisions.

80. A carbon cost adder could, however, indirectly increase costs to ratepayers by altering the resource selection criteria to favor generation resources that emit less CO_2. For example, imposing a CO_2 cost adder gives preference to gas resources over coal resources, and likewise wind resources over gas resources. In response to Chairman Sopkin's request at the Settlement hearing, Public Service provided additional modeling runs on December 15, 2004 demonstrating how CO_2 costs, varying from zero to $9.00/ton, would impact resource selection. These runs are based on the Settlement modeling runs presented on pages 11 and 13 of Attachment D to the Settlement. However, if two resources were very close in costs prior to the imposition of a CO_2 cost adder it could change the resource that is ultimately selected. These runs show that for CO_2 costs between zero and $9.00/ton there is no change in the resources selected under the most likely scenario of the existing IPP contracts extended[9].

[9] Public Service witness Mr. Hill testified that of Strategist Model runs presented in Attachment D to the Settlement, the *IPP Contracts Extended Assumption* was the proper analysis for evaluating and comparing the impact of the Settlement.

81. In addition Company witness Mr. Plunk states in his Direct testimony on page 22, lines 1 to 5, "although Comanche 3 is not subject to enforceable carbon dioxide limitations today, such limitations are a possibility sometime during the life of the unit.[10] Based on the Company's analysis in the 2003 Least-Cost Resource Plan, Comanche 3 would still make good financial sense even if it were subject to aggressive carbon taxes…" In his Rebuttal testimony Mr. Plunk states on page 6, lines 18 to 20, "based on this literature, and my own experience, I believe that the most likely upper bound cost of a CO_2 policy would be in the \$10-\$15 per ton range." He goes on to suggest that a \$12 per ton cost of CO_2 is a reasonable surrogate for the upper range of potential CO_2 compliance costs.[11]

82. We do have some reservations concerning the Settlement's CO_2 cost adder of \$9.00/ton. While we note that no carbon legislation is pending at this time, we find that the testimony of Mr. Plunk and the other Parties which anticipates the imposition of a carbon tax or other CO_2 cost at some point during the 30-year Resource Planning Period to be persuasive. Therefore we find it prudent to approve the Parties agreement to include the \$9.00 per ton cost adder in the resource screening and selection process. While a CO_2 cost may be imposed in the future, we agree with Mr. Plunk's testimony that such costs will be tempered to prevent severe impacts on the economy and be in the upper bound range of \$10 to \$15 dollars per ton[12]. Further the additional modeling provided by Public Service at Chairman Sopkin's request regarding the impact of a \$9.00 per ton CO_2 cost demonstrated to us that it did not impact the resource selection process for this LCP.

[10] Mr. Plunk is the Vice President of Environmental Services. He has been employed by Xcel Energy and its predecessors for over 29 years. During those 29 years, he has served in various capacities in the environmental operations of the Company.

[11] *See.* Mr. Plunk's Rebuttal testimony, page 7, lines 6 to 7.

[12] *See,* Rebuttal Testimony of Company witness Mr. Plunk, page 6, lines 18 –20.

G. Renewable Energy Credit (REC)

83. Initially Public Service proposed not to use any REC values in connection with the LCP resource evaluation process.

84. In his Answer testimony, WRA witness Mr. Gilliam recommended the Commission assign a value for RECs associated with renewable energy resources that is bid into the All-Source RFP. He developed a value of $23/MWh based on the average of two data points. The first source was from the website of a Colorado-based company, Renewable Choice Energy, which resells renewable energy certificates to end-use customers at a price of $40/MWh (or 4 cents per kWh). The second source was a bulk sale by Arkansas River Power Authority and Lamar Utilities at $6/MWh.

85. Public Service witness Ms. Hyde disagreed with Mr. Gilliam's assessment of the economic value of RECs, arguing that Mr. Gilliam's recommended REC value was based on a mix of retail and wholesale transactions. Ms. Hyde believed that a wholesale REC value should be in the range of $2.13/MWh. She noted that if one added the Arkansas River Power Authority/Lamar transaction used by Mr. Gilliam to the value she calculated it would raise the REC value to $3.42/MWh.

86. The Settlement provides that in accord with Section 15(E) of the CECP Stipulation and in recognition of the potential future value of RECs provided to Public Service, particularly after the passage of 2004 Colorado Ballot Initiative Amendment 37, the Company shall include a REC value of $8.75/MWh for all renewable resources bid into solicitations under the 2003 LCP, with the exception of the Renewable Energy RFP issued on August 17, 2004.

87. This REC value is to be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation process. Under the Settlement, Public

Service will apply the REC value to renewable energy resource bids for all operating years of the renewable energy project from 2006 onward. The REC will not escalate in value over the 30-year Planning Period used in the 2003 LCP.

88. We are concerned about the REC level adopted in the Settlement. We agree with Public Service that only wholesale REC values should apply in the LCP analysis, resulting in a REC value less than $8.75/MWh. On a stand-alone basis this REC value artificially reduces the modeled cost of renewable resources, which could result in the selection of resources that do not provide the lowest NPV of rate impacts. We are unclear how the recent passage of Amendment 37 may impact the value of these RECs and the impact of its interplay with the LCP requirement to select the least cost plan. However, the $8.75/MWh level appears to be a negotiated term, contributing to the overall benefits of the comprehensive Settlement. We also note that on Page 13 of Attachment D[13], there is no change in the renewable energy resources selected by the Strategist Model under all of the scenarios presented.[14] This is particularly relevant when one compares the two Rebuttal Scenarios, which used a REC value of $2.14/MWh and the Settlement Scenario, which used an $8.75/MWh value. We conclude that even with the higher REC value, it did not impact the resources selected by the Strategist Model.

89. We are also persuaded that given the passage of Amendment 37 , which requires, among other things, Public Service to acquire a certain percentage of its resource needs with renewable energy resources, that RECs will become increasingly valuable.

[13] Public Service Witness Mr. Hill testifies that of Strategist Model runs presented in Attachment D to the Settlement, the *IPP Contracts Extended Assumption* was the proper analysis for evaluating and comparing the impact of the Settlement.

[14] For the year 2006, Strategist selects six units of 80 MW Production Tax Credit Subsidized Wind. This reflects the 500 MW of wind resources to be acquired under the Renewable Energy RFP in Docket No. 04A-325E.

H. The 56% Equity Level

90. The Company originally sought pre-approval to recognize the imputed debt attributed to Public Service from its existing purchase power contracts for the 2006 rate case. According to the Company, its credit objective is to achieve a S&P senior unsecured debt rating of BBB+. Its current senior unsecured debt rating is split because the S&P rating on senior unsecured debt is BBB-, while Moody's rating is an S&P equivalent of BBB+.

91. Public Service contended its credit metrics have been weakened by the use of purchased power to meet its customers' energy needs. According to the Company, S&P adjusts the ratios which are used to calculate a company's financial metrics for rating purposes, to include the impact of "fixed charges" for such things as leases and purchased power.

92. Staff asserted that Public Service has presented no testimony or evidence establishing that it is currently having troubles securing capital. Additionally, Staff argues that contrary to the Company's testimony, the financial benchmarks are not the sole determinants for establishing credit ratings. Staff posits that Public Service has exaggerated the debt rating issue as an attempt to justify it's request for the pre-approval of the 56% equity level. While Staff did not conceptually oppose the proposal to increase equity, it did not believe that the Commission should choose a particular capital structure in this resource acquisition proceeding. Instead, Staff argued that the proper level of equity should be determined in the next rate case proceeding. Staff recommended that the Commission not grant this request since it would mean that the Commission would have less flexibility in its regulation of Public Service in the future.

93. The OCC shared the same opinion that a review of capital structure and all other revenue requirement issues should be addressed in the 2006 rate case. The OCC also noted that the Company's equity levels were increasing during the test year of the last rate case (Calendar

Year 2001 for an average of 51.4 percent). Starting in August 2002 they fell to the low 46 percent. Beginning in 2004, they have risen slightly to 46.88 percent.

94. In its Rebuttal testimony, the Company clarified that it wasn't requesting approval of a hypothetical capital structure of 56 percent. Instead it expects to achieve an actual capital structure of 56 percent by December 31, 2005. The Company contends that none of the witnesses appreciate the significance of the fact that its senior unsecured debt is a one step reduction in rating to below investment-grade. Public Service performed a projected liquidity requirement in the event of a credit downgrade combined with a +/- 30 percent change in natural gas prices to conclude that it would have potential liquidity requirements in the range of $324 to $360 million.

95. As part of the Settlement, the Parties recognize the Company's need to increase its equity ratio, as calculated for financial reporting purposes, to 56 percent in order to offset the debt equivalent value of existing purchased power agreements and to improve the Company's overall financial strength. The Parties agree that, for purposes of the 2006 Phase I rate case, the actual regulatory capital structure shall be deemed reasonable and shall be used to determine the Company's 2006 Phase I rate case revenue requirement. This actual regulatory capital structure includes pro forma adjustments, but excludes short-term debt. It is based on the earlier of the date on which a Settlement of the 2006 Phase I rate case is executed or the first day of evidentiary hearings. The Parties recognize that depending upon the level of short-term debt on the Company's balance sheet as of the date the regulatory capital structure is determined, the equity ratio could exceed 56%.

96. Public Service stipulates that, for purposes of the 2006 Phase I rate case, its proposed regulatory capital structure would not exceed 60% equity. Under the Settlement,

Public Service reserves the right to seek higher levels of equity in its regulatory capital structure in Phase I rate proceedings subsequent to the 2006 rate case. Likewise, the Parties reserve their rights to take a position that reflects their respective interests at such time.

I. Current Earnings on Comanche Construction Work In Progress (CWIP)

97. The Company sought pre-approval to include the Comanche 3 and the related transmission CWIP account balances in rate base without an Allowance for Funds Used During Construction (AFUDC) offset in the expected 2006 rate case. The Company's request also extended to any other rate cases which may occur prior to Comanche 3 going into service. Public Service proposes to have Comanche 3 in-service during 2010.

98. Several of the Parties in the case argued that allowing current earnings on a plant under construction violates the long-standing regulatory principle of "used and useful." They argued that the used and useful principle has two important incentives: first, to complete the project on time; and second, to finance the construction efficiently. It was pointed out that previous Commissions have allowed current earnings on CWIP, however, that occurred when Public Service was suffering from financial stress.

99. In its testimony, Staff indicated it was willing to consider the concept of some current earnings on Comanche CWIP if the Commission grants a CPCN for Comanche 3. However, Staff felt that the determination on whether current earnings on CWIP should be permitted should be done in the context of a rate case proceeding, not a resource acquisition proceeding.

100. The Company responded that although Staff has suggested allowing Public Service to earn on Comanche CWIP instead of the LCPA rider, this may not provide it with adequate cash flow during construction of Comanche 3.

101. Pursuant to the Settlement, in any Phase I rate proceeding that the Company may file between January 1, 2006 and the later of January 1, 2011 or five and one-half years after the Company secures an administratively final air permit for Comanche 3, provided that the Company's actual capital structure used for regulatory purposes equals or exceeds 56 percent equity, the Company would be entitled to the following treatment of CWIP associated with the construction of Comanche 3, the installation of environmental controls on Comanche 1, 2, and 3, and related transmission investment (Comanche CWIP):

a) If on the earlier of the date on which a Settlement of the Phase I rate case is executed or the first day of evidentiary hearings, the Company's senior unsecured debt rating from either S&P or Moody's is below A- or its Moody's equivalent, the Company would be permitted to include Comanche CWIP in ratebase without an AFUDC offset, calculated as of the end of the applicable test year.

b) If on the earlier of the date on which a Settlement of the Phase I rate case is executed or the first day of evidentiary hearings, the Company's senior unsecured debt rating from either S&P or Moody's is below BBB+ or its Moody's equivalent, the Company shall be permitted to make an out-of-period adjustment to include Comanche CWIP in rate base without an AFUDC offset, accrued during the period ending twelve months following the end of the test year upon which the Phase I filing is based. The Parties acknowledge that the Company's Phase I filing will include the Company's best estimate of the Comanche CWIP balance as of the end of the twelve month period following the end of the applicable test year, which estimate may be revised from time to time up until 30 days prior to the first day of scheduled evidentiary hearings in the Phase I rate case.

c) If Public Service's actual capital structure used for regulatory purposes does not equal or exceed 56%, or if Public Service's senior unsecured debt rating from both S&P and Moody's is at or above A- or its Moody's equivalent, then the Parties reserved their rights to take a position with respect to Comanche CWIP that reflects their respective interests at such time. If the Company's senior unsecured debt rating from both S&P and Moody's is BBB+ or its Moody's equivalent, then the Parties reserved their rights to take a position with respect to the Comanche CWIP pro forma adjustment discussed in Paragraph b that reflects their respective interests at such time.

d) Public Service reserves the right to seek additional regulatory relief associated with the construction of the Comanche Project or the impact of purchased power at any time, except that the Company agrees that it shall not seek a rider specific to recovery of the financing costs of Comanche 3 and the Company shall not file an electric Phase I rate case prior to January 1, 2006. The Parties reserve their rights to take a position that reflects their respective interests with regard to such additional regulatory relief requests

102. We find that the BBB+ senior unsecured debt rating at which a party may contest the out-of-period adjustment for projected construction expenditures on Comanche investments is reasonable given that it contributes to the Parties ability to advocate for approval of the comprehensive Settlement. The group most affected by this provision of the Settlement is the ratepayers. It should be noted that there is a direct link between the debt rating of the utility and the cost of capital. When a utility's cost of capital increases due to lower debt ratings, it is directly reflected in the rates charged consumers, all other things being equal. To the extent that construction of Comanche 3 could negatively impact Public Service's financial health and debt rating due to the size of the expenditures and the timeliness of the recovery of those expenditures, the out-of-period adjustment for Comanche CWIP should help alleviate the financial exposure of Public Service. This is not to say that ratepayers should open their checkbooks to prop-up their local utility's debt rating. There must be a balance. Ratepayers should receive many benefits from the construction of Comanche 3 because of the synergies created by the brownfield site and anticipated expedited construction timeline.

103. An additional benefit of the inclusion of the out-of-period adjustment is the gradual increase in rates rather than a large increase, due to the slow increase in the size of the rate base by including the out-of-period adjustment in future rate cases. Large step rate increases would likely cause rate shock for customers that have a limited ability to plan for or absorb large changes in their utility bills.

J. Ruling on the Settlement:

104. We first consider whether to approve or deny the Settlement based on the overall benefits it provides. We then consider whether we should modify specific terms of the Settlement, to achieve a better overall balance to the stipulation.

105. Examining the Settlement from a monetary impact first, we note the difference between the Settlement scenario and Public Service's Rebuttal case equates to a $90 million revenue reduction (in 2003 present value dollars) and $0.05/MWh rate increase for the Settlement over the 30-year planning period. The difference between the Settlement scenario and the generic screening scenarios equates to a revenue reduction of $500 million to $1.3 billion (in 2003 present value dollars), and a rate reduction of $0.58 to $2.14/MWh for the Settlement over the 30-year planning period. If the implementation of Comanche 3 was delayed by litigation in Public Service's Rebuttal case, as is likely without the Settlement resolution, the costs would trend upwards toward the generic screening scenarios. Consequently, we put more weight on the generic screening comparisons, which shows that the Settlement provides a significant reduction in rate impact. These appear to be real cost savings to all ratepayers.

106. Public Service provided compelling evidence that an earlier in-service date for Comanche 3 should reduce costs to ratepayers. We find that the proposed Settlement will help achieve an early in-service date . The Settlement allows Public Service to apply for Comanche 3 air permits by showing a net reduction in regulated emissions, while implementing a comprehensive mercury mitigation program. The terms of the Settlement, as well as the comprehensive list of signatories present a comprehensive package where the primary environmental and Pueblo area community groups agree that all reasonable steps have been taken to minimize the impacts of Comanche 3, and Public Service's overall least cost plan. We find that the Settlement will almost certainly eliminate CPCN process delay and will likely reduce air permit delays. Further, we find that the Comanche 3 construction cost cap adequately limits ratepayer cost exposure, as well as providing a necessary incentive for Public Service to properly manage the project.

107. We find that the Settlement provides greater benefits than could be achieved through an adjudicated proceeding. We agree with the Parties that a timely implementation of Comanche 3 will provide substantial benefits to ratepayers. Though rates will increase because of the many additional resources to be acquired through this LCP, the Settlement also provides sufficient offsets through the required level of DSM and renewable energy requirements.

108. We also find that the Settlement reduces reliance on gas-fueled generation by implementing at least 750 MW of coal-fired generation, while increasing the amount of wind generation and DSM measures. This is important in light of the increasing costs and price volatility of natural gas. As stated in Public Service's LCP, "in the last ten years the PSCo system generation fuel mix has gone from six percent natural gas based in 1995, to 48 percent natural gas based in 2004.[15]

109. Pursuant to § 40-2-123, C.R.S. we are to "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in [our] consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases. *Id*. We find that this Settlement allows us to give the fullest possible considerations to those statutorily required matters. We find that the overall terms of the Settlement, as well as the inclusive list of signatories, present a package where the major environmental groups agree that reasonable steps have been taken to minimize the emissions associated with Comanche 3, as well as Public Service's overall least-cost plan. The Settlement also provides a mechanism for a speedy and expedient approval and construction process for Comanche 3.

[15] LCP Volume 1, page 1-10.

110. Next, we consider whether the Commission should modify specific provisions of the Settlement to comply with the LCP Rule requirements. As discussed *infra,* the REC, DSM, and CO_2 provisions on a stand-alone basis do not appear to be consistent with the LCP Rules and could possibly have the effect of artificially raising rates. However, the benefit of a timely Comanche 3 in-service date should outweigh the costs associated with these provisions. These benefits to ratepayers should not only reduce overall utility costs, but also reduce the NPV of rate impacts, as required by the LCP Rules. Because the Settlement as a whole is consistent with the intent of the LCP Rules, we do not find it necessary to modify the Settlement.

111. Lastly, we consider whether the Commission should modify the terms of the Settlement so that it is in the public interest. We have some concerns regarding the resolutions relating to the RECs, CO_2, and DSM as proposed in the Settlement. However, taken as a whole, we find the Settlement provides an equitable resolution to the Parties' positions, while at the same time providing the best long-term outcome for ratepayers. As discussed *infra,* the Parties appeared to reach a compromise with regard to these provisions that reflects a negotiated agreement; not directly based on a stand-alone determination of the merits of the terms. However, we recognize that it is significant that all environmental groups in this case have agreed not to contest the proposed 750 MW Comanche 3 pulverized coal generation plant, and we believe that there is a real risk of destroying the Settlement if we modify the terms. The Commission has the authority to modify individual Settlement terms, but the Parties would then have a right to withdraw from the Settlement. This particular Settlement presents an unusual situation to the Commission. If any individual Party withdraws from the Settlement in response to a Commission modification, nearly all of the benefits of the Settlement may be lost. This would jeopardize the accelerated timing of Comanche 3, eliminating the primary benefit of the

Settlement. Furthermore, the areas of concerns discussed above do not have significant impacts on the overall outcome of resource selection, and do not warrant the risk of jeopardizing the Settlement. Comanche 3 provides a unique opportunity for Public Service, its ratepayers, the environmental groups, and the Pueblo area community groups. We commend the Parties for their hard work and diligence in reaching such a sweeping Settlement. We find it in the best interest of the ratepayers to approve it without modification.

K. Ruling on the DSM Waiver

112. The Parties state that they do not request the Commission to rule on the issue of whether the DSM program proposed in the Settlement requires a rule waiver, but if such waiver is necessary it would be in the public interest to grant the waiver. We find that a waiver is required for the Settlement DSM program. First, The TRC test for the proposed DSM program clearly violates the intent of the LCP rules, as discussed in detail in the DSM section. Second, Rule 3610 (b) requires the utility to meet its resource need through a competitive acquisition process, unless the Commission approves an alternative method of resource acquisition. To the extent that the DSM proposal applies under this Rule, Public Service has not proposed to include it within its waiver request. Third, Rule 3610 (b) limits the exemption from competitive resource acquisition to 250 MW. The Settlement already proposes to exceed the 250 MW exemption limit with the 750 MW rate-based Comanche 3 plant. As discussed in detail in the DSM section, the Settlement as a whole meets the intent of the LCP Rules by minimizing NPV rate impacts. Therefore, we find that the Commission should grant a waiver from Rule 3610(b) to allow Public Service to implement 320 MW of DSM without a competitive resource acquisition process.

III. ORDER

A. The Commission Orders That:

1. The Motion filed by Public Service Company of Colorado to approve the Settlement Agreement to the above captioned dockets is granted.

2. The Comprehensive Settlement Agreement is approved in its entirety and is attached to this order.

3. Sections 3, 4, 5, 6, 7, 8, 12, 14 and 15 of the Concerned Environmental and Community Parties are approved and included as Attachment A in the Comprehensive Settlement Agreement attached to this order.

4. The 20-day time period provided by § 40-6-114(1), C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the mailed date of this Order.

5. This Order is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING December 17, 2004.

(S E A L)

ATTEST: A TRUE COPY

Bruce N. Smith
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

POLLY PAGE

CARL MILLER

Commissioners

CHAIRMAN GREGORY E. SOPKIN
CONCURRING, IN PART, AND
DISSENTING, IN PART.

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IV. <u>CHAIRMAN GREGORY E. SOPKIN CONCURRING, IN PART, AND DISSENTING, IN PART:</u>

A. Introduction

Why anyone would expect better decisions to be made by third parties who pay no price for being wrong is one of the mysteries of our time – Thomas Sowell

1. The Settlement Agreement sanctioned by many parties to this case resembles an omnibus budget bill – that is, it doles out pork to many special interests, without sufficient regard for the party left unrepresented in the transaction: the ratepayer. In my view, our primary duty as an *economic* agency is to protect the ratepayer from overreaching by parties who put their own interests above all else. It is our economic expertise that enables us to make sound decisions on economic matters. When we let matters foreign to our expertise (speculative future environmental taxes and credits) and outside our control (the threat of litigation) outweigh the interests of those who will pay the resulting higher rates for the next few decades, we exceed the legislative delegation entrusted to the Commission, and our decision is entitled to little credibility.

2. We are an economic agency. We are advised by economists, engineers, financial advisors, and lawyers. We have not one environmental expert upon whom we can rely. The Commission nevertheless presumes what the likely carbon tax might be in the future. In effect, the Commission has imposed a new regulation on an emission (carbon) that has not been classified as a pollutant. The decision on that classification belongs to the Environmental Protection Agency, the Colorado Department of Public Health and Environment, and state and federal legislatures. It is not for us to *de facto* (or *de jure*) classify carbon as a pollutant. When an economic agency, as part of a *quasi-judicial* proceeding, acts as a legislature without

legislative process or an agency without relevant expertise, the action has no procedural or substantive legitimacy.

3. Of the four provisions in the Agreement I dissent from today, the carbon tax imputation especially stands out as extra-jurisdictional, speculative, and utterly without foundation. Based on the grim-faced testimony of experts who have no expertise (no one can) in divining what Congress may or may not do in the coming decades, the Commission has apparently been persuaded that such a tax is "likely." The only competent evidence on the issue – that Congress has never passed such a measure, all going down to substantial defeat for fear of harming the economy – has been given little weight.

4. More importantly, upon what authority does the Commission impose what only can be characterized as a tax on over one million Coloradoans (Public Service Company customers)? Placing the issue before the legislature would have two senses of legitimacy absent here, namely, voter representation (and its attendant accountability), and receipt of arguments on both sides of the issue.[16] In our quasi-judicial evidentiary hearing, no party advocated that a future carbon tax is *not* likely or should *not* be imposed by the Commission. Those who would pay were not adequately represented in this regard. By contrast to our proceeding, the legislature would at least hear from the opposition.[17] While we don't know how voters might react to a

[16] "Hear one side and you will be in the dark. Hear both and all will be clear" – Lord Chesterfield.

[17] The EPA and CDPHE also would hear from the opposition as part of any determination on regulation of pollutants.

carbon tax proposal, we do know that a legislative act on the issue originates from an appropriate and accountable governmental body.[18]

5. All of this is rationalized in an attempt to prevent litigation. But our attorneys can do nothing to stop parties (and non-parties) who are not signatories to the Agreement from litigating the air permit or appealing the decision rendered today. The Commission should not capitulate to special interest demands that harm the ratepayer out of fear of litigation without at least assessing its likelihood of success (and associated likelihood of delay cost), something that did not occur in this case.

6. While the overwhelming majority of the Settlement provisions constitute legitimate compromise and are in the public interest, four are, in my view, clearly not: (1) the allowance for Public Service Company in its 2006 rate case to recover costs 12 months beyond the test year if it has a credit rating of BBB+; (2) imputing a fictional and speculative carbon tax on non-intermittent generation resources (i.e., coal and gas plants), making them less likely to be selected as a "least cost" resource; (3) a Renewable Energy Credit that is inflated by irrelevant retail REC value evidence; and (4) $287 million (nominal) spent by Public Service Company over ten years for Demand Side Management programs that increase the rates of the ninety-six percent of ratepayers who do not participate in the programs, and subsidize wealthier ratepayers and free riders.

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[18] We also know that voters long ago passed an initiative requiring that tax increases be approved directly by voters (the Taxpayer Bill of Rights). To understate, it is a departure from this principle for unelected, appointed Commissioners to impose a tax without voter input. The Colorado Supreme Court has voiced concern over the power of the Commission to enact preferential rates to effect social policy because, "[t]o find otherwise would empower the PUC, an appointed, nonelected body, to create a special rate for any group it determined to be deserving." *Mountain States Legal Foundation v. Public Utilities Com'n*, 590 P.2d 495, 498 (Colo. 1979). The same concern should exist over an executive agency effecting a different social policy wholly outside its competence.

B. Fear of Litigation

Important principles may, and must, be inflexible – Abraham Lincoln

7. The danger here is, as in any major case, the Commission will not dare reject any portion of a settlement out of fear that a party will leave the settlement and litigate through hearing and appeal of the result. This effectively takes the Commission out of the equation, and gives parties freer reign to trade items that benefit them but not the ratepayer. Utilities are relatively indifferent to acceding to party (and, in this case, non-party) demands so long as there is recovery from ratepayers and a willing agency. In future major cases, we can expect dozens of special-interest parties to intervene and leverage the litigation threat, knowing there is a strong likelihood that both the utility and the Commission will acquiesce.

8. I do agree that, when deciding whether to accept a settlement, it is legitimate to consider the potential of a party leaving the settlement and resultant delay costs. But the analysis is incomplete without considering the ability of the Commission to control subsequent litigation, and the likelihood of success of such litigation. In this case, there are ten intervening parties who have either not signed the Agreement or take no position on it.[19] There is a substantial chance they could appeal today's decision in the state court system. This allows for the worst of both worlds: acquiescence to less desirable provisions, and litigation anyway.

9. Public Service Company asserts that accepting the settlement *in toto* is in the public interest because litigation could delay construction of the Comanche 3 coal plant, which could cost ratepayers hundreds of millions of dollars. However, when questioned whether a *state* court appeal would result in delay of the Comanche 3 coal plant project, the attorney

[19] Some parties have indicated they take no position on the Agreement but will not challenge it. I do not count these among the ten referenced above.

representing the Company stated that whether the Company would pursue construction of the plant "would depend upon our assessment of the likelihood of the appealing party succeeding on the merits of the appeal."[20] The Company will assess the likelihood of success of any appeal; so should the Commission.

10. The four Agreement provisions to which I dissent - (1) recovery of costs twelve months beyond the rate case test year; (2) imputation of a speculative carbon tax on the RFP process; (3) the amount of the Renewable Energy Credit; and (4) the amount of dollars spent over ten years for DSM – are *policy* matters. There is no legal statute or rule that compels the Commission to accept any of these provisions. If the Commission imposed the changes I advocate, the possible bases of appeal would be limited.[21] Given the deference traditionally afforded the Commission regarding factual and policy (as opposed to legal) matters,[22] these bases are extremely unlikely to succeed. As noted in *Public Service Co. of Colorado v. Trigen-Nations Energy Co.,* 982 P.2d 316, 322 (Colo. 1999):

> A PUC decision is final and not subject to review, except on the ground that it violates a constitutional or statutory right or duty, whereupon the district court and we, in turn, have responsibility to exercise an independent judgment on matters of law, … with due deference to PUC's fact-finding and policy-making roles. The district court acts to set aside or modify a PUC decision in the event of legal error; otherwise, it shall affirm the agency's action.

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[20] Transcript, Vol. 14, p.92. This pursuance of construction assumes the grant of the CPCN is not stayed. *See id.*

[21] Review of a PUC decision is limited to whether the PUC has regularly pursued its authority, whether its decision is just and reasonable, and whether its conclusions are in accordance with the evidence. C.R.S. § 40-6-115(3). Orders of the Commission are presumed to be reasonable and valid, and the party challenging an order bears the burden of showing its impropriety. *Atchison, Topeka and Santa Fe Ry. Co. v. Public Utilities Com'n***,** 763 P.2d 1037, 1041 (Colo. 1988).

[22] *Atchison, supra,* 763 P.2d at 1041-42, summarizes this well: Factual determinations of the Commission are entitled to considerable deference; a reviewing court must view the evidence in the light most favorable to the Commission; it may not disturb those factual determinations that are supported by substantial evidence in the record; findings may not be set aside merely because the evidence before the Commission is conflicting or because more than one inference can be drawn from the evidence. nor may a reviewing court substitute its judgment for that of the Commission. *See also Integrated Network Services, Inc. v. Public Utilities Com'n***,** 875 P.2d 1373, 1377 (Colo. 1994) ("the PUC is an administrative agency with considerable expertise in the area of utility regulation and, as such, its decisions should be accorded due deference").

Therefore, the potential for costly delay is exaggerated.

11. We also are asked to pay heed to an outside settlement agreement – the so-called CECP[23] Agreement – entered into by Public Service Company and certain parties *and non-parties* to this case. More specifically, we are asked to approve special interest demands of a handful of non-party environmental groups lest they appeal the Company's application for an air permit for the Comanche 3 facility. It is fatuous, in my view, to let outsiders to a case affect our decision on a matter over which we have no control. That a few groups have agreed to not contest the air permit does nothing to prevent dozens of other groups with similar interests from doing the same. The Company admits this:

> Q. Now, Mr. Prager, the settlement agreement that's in Attachment A has numerous environmental parties on it; but is it sufficient to completely prohibit all challenges to the company's air permit?
>
> A. The answer to that question is unfortunately no. …
>
> … [A]ny citizen has a right to undertake actions that could result in a challenge to the permit for Comanche 3, and we cannot bind every citizen in the state of Colorado.[24]

It is relatively easy for well-funded groups or activists to legally contest an air permit application. Again, the relevant inquiry is the likelihood that such litigation will succeed; and Public Service Company has opined that, given the environmental controls it will add to the entire Comanche facility (resulting in a net *reduction* of major regulated pollutant emissions of the facility), such litigation likely will not succeed.[25] If there is such litigation, again we have the

[23] Concerned Environmental and Community Parties.

[24] Company witness Frank Prager, Transcript, Vol. 14, p.111-112.

[25] Company witness Prager stated that "we think that any challenge of our permit is unlikely to succeed" because of, among other things, the number of issues in this case addressed by the Company. Transcript, Vol. 14, p.112. While Mr. Prager also opines that the chance of success decreases because of the identity and number of environmental parties joining in the settlement, *see id.,* I do not agree that the absence of certain complainants can affect the substantive merits of any challenge.

worst of both worlds: acceding to imprudent demands, and litigation anyway.

12. I am well aware of the concept of the perfect as the enemy of the good, and that the Commission generally encourages settlement. I do not cavil to the insignificant. In this case, the principles that I believe should not be compromised are that the Commission should refrain from imposing costs on all ratepayers to subsidize a select few who need no subsidization; the Commission should not decide matters based on speculation or insufficient record evidence; and, that the Commission should not decide matters over which it has no expertise and are outside the scope of the docket. The Commission must not abnegate its responsibility as the last check of what is in the ratepayer's interest.

C. Advanced Recovery

> People can foresee the future only when it coincides with their own wishes, and the most grossly obvious facts can be ignored when they are unwelcome – George Orwell

13. On the issue of advanced recovery, I do not agree that the Commission should dismiss the "used and useful" principle absent extraordinary cause. Under the Settlement Agreement, if Public Service Company's senior unsecured debt rating is *below* BBB+, the Company will include Comanche construction work in progress (CWIP) in rate base (in the 2006 rate case) without an AFUDC offset and also include an out-of-period adjustment for up to 12 months after the end of the test year for Comanche investment expenditures. If the Company's debt rating is *at* BBB+, the Company will still include Comanche CWIP in ratebase without an AFUDC offset, but the parties can take their own position regarding the out-of-period adjustment.

14. A twelve-month out of period adjustment to rate base does not comport with the used and useful principle because it places into rate base expected 2006 capital expenditures (outside of the 2005 test year) on Comanche 3 before the plant goes into service. While I do think the Commission generally has a responsibility to ensure the financial viability of the Company while it undertakes a capital-intensive project, there should be evidence that its viability is indeed threatened before departing from traditional ratemaking practice. According to Public Service Company witness Benjamin Fowke, "the reality is, we would have to [wait] through the end of the [2006] rate case" before the company could expect improvement to a BBB+ rating.[26] And it appears impossible for the company to ever achieve an A- rating as a result of having imputed debt from purchase power obligations.[27] So it is very unlikely that the company will achieve a BBB+ rating anytime in the near future. Given that the twelve-month out of period adjustment will be automatically allowed unless the improbable upgrade to BBB+ occurs, the Commission is, by approving this provision, essentially guaranteeing the adjustment.

15. Therefore, I do not agree with the two thresholds described above: "below BBB+" and "at BBB+," respectively. I would modify them to "below BBB" and "at BBB," respectively, so that, if the Company's rating has improved to BBB at the time of the rate case in 2006, parties would be free to argue whether an out of period adjustment of up to 12 months is necessary or unnecessary.

D. The Carbon Tax

This is one of those cases in which the imagination is baffled by the facts - Adam Smith

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[26] Transcript, Vol. 8, p.128. (Parentheticals correct or clarify obvious mistakes in the record.)

[27] Company witness Benjamin Fowke states in his Direct Testimony (at p. 15) that "[s]enior unsecured debt ratings above BBB+ usually require a level of equity capitalization, ROE and depreciation levels that are higher than regulated utilities can maintain."

16. One first has to presume that the Commission has jurisdiction to impute a carbon tax to the RFP process before considering what amount is justified based on a preponderance of the evidence. As indicated above, I do not. The Commission's authority is limited by statute.[28] The General Assembly legislature has not seen fit to give the Commission jurisdiction over classification of pollutants, imposition of taxes, or social policy[29] in the guise of generation acquisition supervision. Given our lack of expertise on the issue and the existence of other agencies with both the appropriate legislative delegation and requisite expertise on environmental matters, we should have the modesty to dismiss the issue as beyond our purview and therefore outside the scope of this docket.

17. Assuming away the jurisdictional failing, the absence of evidence to support the assumption of the carbon tax is gaping. The totality of evidence suggesting the inevitability of such a tax amounts to grim-faced witnesses declaring, to paraphrase, "it's going to happen – you'll see." Even if one assumes this to be true, the when and how much of such tax are entirely speculative. The people making these suppositions may have expertise concerning existing laws or climate change, but no one has expertise over what legislation Congress or regulation the EPA might, or might not, impose on carbon in the next three decades.[30] For that reason, I believe the evidence of "inevitability" is not competent.

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[28] While the Commission has been delegated legislative authority to regulate utilities pursuant to Article XXV of the State Constitution, such authority cannot exceed Colorado statute. *See Mountain States Legal Foundation v. Public Utilities Com'n***,** 590 P.2d 495, 497 (Colo. 1979).

[29] *See, e.g., Mountain States, supra,* at 498 ("although the PUC has been granted broad rate making powers by Article XXV of the Colorado Constitution, the PUC's power to effect social policy through preferential rate making is restricted by statute no matter how deserving the group benefiting from the preferential rate may be").

[30] Under Rule of Evidence 702,admissible expert testimony must be based on actual knowledge and not subjective belief or unsupported speculation. *Lovato v. Burlington Northern and Santa Fe Ry. Co.,* 2002 WL 1424599 at *5 (D. Colo. June 24, 2002). While witness Olon Plunk has 29 years of experience at Public Service Company in environmental matters, this does not make him a Congressional action prophet.

18. Much of this revolves around the global warming dispute. While the Commission should not and did not opine over the extent and causation of warming, to say there is no valid debate – as some witnesses indicated[31] – is an abject distortion of reality.[32] Anyone with a passing interest in the subject knows that scientists continue to debate why, if such warming exists and is caused by the technological emissions of mankind, cyclical cooling and warming periods lasting decades or hundreds of years have been occurring for thousands of years, well before the industrial revolution. Whether regulation or a tax on carbon emissions in the U.S. would have much global effect is in doubt.[33] There also is debate over whether there may be benefits to minor warming, such as increased agricultural production. The point is not to decide the merits of the debate, but to acknowledge there is one. That climactic science is relatively young (e.g., the theory of global cooling espoused only three decades ago), and complicated by numerous variables known and unknown, means the debate surely will continue for the next several decades. This debate will affect whether the American public (through their representatives) believes the costs of carbon controls exceed any putative benefits.

19. The only competent evidence presented at hearing on the likelihood of such a tax is that every attempt at imposition has been soundly defeated. For example, the Senate unanimously refused to consider Kyoto Protocol Treaty by a vote of 95-0, and the McCain-

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[31] *See* testimony of Gary Nakarado, Transcript, Vol. 8, pp. 74-75 ("I think, to my knowledge, all publicly appointed groups of scientists who have looked at this issue have all concluded that the climate change is a manmade phenomenon." When questioned about academic experts who hold an opposing view, Mr. Nakarado ascribed this to: "people with significant economic interests have funded so-called climate scientists to take opposing views"). *See also* Cross Answer testimony of Dr. James White, pp. 5-6 ("on the question of the existence of climate change and in particular, global warming, the evidence is so overwhelming that there is no real debate on this issue anymore").

[32] "We can never be sure that the opinion we are endeavoring to stifle is a false opinion; and if we were sure, stifling it would be an evil still" - John Stuart Mill.

[33] According to expert witness James White, "Kyoto is a baby step, to be quite honest. It's not going to reduce CO-2 levels by average amounts in the atmosphere." Transcript, Vol. 11, p.20.

Lieberman Act was defeated 55-43.[34] Congress appears reluctant to impose any such tax for fear of harming the economy.[35]

20. From this, the Commission somehow concludes that a carbon tax is likely enough in the future that we should impose it now on ratepayers. Some may object to this terminology; I find no way to avoid it.[36] The Agreement (at ¶ 18) states:

> As required by section 12 of the CECP Settlement and in consideration of the potential incurrence of future costs due to greenhouse gas regulation (e.g., carbon dioxide taxes or allowance costs) during the 30 year Planning Period of the 2003 LCP, the Parties agree that all evaluations of resources acquired under the 2003 LCP should include imputation of CO costs of $9/ton beginning in 2010 and escalating at 2.5% per year beginning in 2011 and continuing over the planning life of the resource. The imputed cost of CO2 shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation processes.

Public Service Company witness David Eves testified that the 2.5% escalation increases the imputed cost each year of the Planning Period such that the imputed cost will be $11.52/ton in year 10, $15.12/ton in year 20, and $19.35/ton in year 30.[37] This will increase the cost of coal and natural gas non-intermittent generation relative to other resources, and thus decrease the likelihood of selection of such generation.[38]

21. If the Commission did possess the authority to impute a carbon tax to the bidding process, the proper analysis would be: Does the preponderance of the evidence show that a

[34] Testimony of Olon Plunk, Transcript, Vol. 4, p. 152.

[35] *See generally* testimony of Olon Plunk (Rebuttal and Transcript, Vol. 4)..

[36] One of the definitions of the word "tax" is "[a] fee or due levied on members of an organization to meet its expenses." American Heritage Dictionary (2nd ed.) at 1246. Since the (largely involuntary) members of Public Service Company will be held responsible for the higher cost of resources that displace any lower cost carbon-emitting resources, the carbon tax imputation meets the "true sense" of the word tax.

[37] Transcript, Vol. 15, pp. 81-82.

[38] The imputation also will increase the cost of coal relative to natural gas resources (because carbon emissions from coal is roughly twice that of gas), meaning a higher cost gas resource may be selected over coal as a result of the imputation. Since the natural gas commodity cost has almost tripled since 2001 and is expected to remain extremely volatile over the next several years (in contrast to the relatively stable cost of the coal commodity), displacing coal with gas may result in substantial costs to the ratepayer.

carbon tax is likely to be imposed on ratepayers at a time and in an amount such that ratepayers would be worse off if the Commission does *not* impute the $9 escalating carbon tax? Economic theory suggests that, if Congress passed a tax effective at the same time and in the same amount as the imputed tax, ratepayers would be no better or worse off than if the Commission does not impute the tax. If Congress passes a tax that is more than that which would be imputed by the Commission (and/or the equivalent or greater tax takes effect earlier than the imputed tax), then ratepayers would be better off by the Commission's tax imputation because resources that would cost them more than the imputation would not be built (i.e., would not be selected in the RFP process). On the other hand, ratepayers will be worse off if no carbon tax is passed during the Planning Period, or if a tax is imposed in a lesser amount (and/or the equivalent or lesser tax takes effect at a later time) than the Commission-imputed tax.[39]

22. Therefore, it is only in the higher (or earlier-imposed) actual carbon tax scenario that it makes economic sense for the Commission to impute the $9 escalating tax (again, assuming it has the authority). Since there is no competent evidence that such an actual tax is likely to be imposed – and there is competent evidence to the contrary – the record does not support the Commission's adoption of the imputed tax.

23. The only defense offered to the carbon tax imputation is that Public Service Company's modeling run showed, under certain assumptions, that the imputation will have no effect on choice of generation resources over the planning period. Assuming for the moment this will bear true, I ask why, then, did certain parties advocate the imputation? And why should the Commission bother to impose such an extra-jurisdictional and speculative cost onto ratepayers?

[39] *See generally* testimony of David Eves, Transcript, Vol. 15, pp. 82-86.

24. I suspect it is more than an academic exercise. The actual choice of resources after the RFP bidding process is completed may look much different than that predicted by modeling runs (as it has in the past).[40] The imputed carbon tax may well make the difference between whether a coal or gas resource is selected, for example.[41]

25. Indeed, one modeling run showed that, under one assumption, a *non-PTC-subsidized* wind resource would be selected as a result of the imputation.[42] That wind may be competitive without the Production Tax Credit subsidy ($18 per MWh) illustrates the real-world costs that may be imposed on ratepayers.

26. It is far from clear that the coal plant cost assumption built into Public Service Company's modeling run will prove accurate. One of the primary issues debated in this case was whether the competitive solicitation process in the Commission's LCP rules is appropriate for large baseload plants such as Comanche 3. The Commission by its decision today waives the rule imposing the 250 Megawatt limitation on utility self-build, which in my view is an implicit finding that the Company presented sufficient evidence to show that, due to timing and brownfield site advantages, a 750 Megawatt coal plant can be built cheaper by the Company than that which might result from competitive solicitation. However, the Company assured us, there is room for more coal plants to be built by the year 2012 or 2013 through the competitive solicitation process. Yet, as this case reveals, substantial doubts remain whether a greenfield coal

[40] As stated by Public Service Company witness James Hill, "[w]e don't know what the bid prices for coal would be." Transcript, Vol. 2, p.72.

[41] According to Company witness David Eves, the carbon tax imputation "basically puts about a $3-per-megawatt-hour penalty on coal compared to efficient combined cycle gas, all else being the same." Transcript, Vol. 1, pp.144-45.

[42] Attachment D to Comprehensive Settlement Agreement, p.11.

plant site may be bid by independent power producers at a lower cost than other, non-coal resources.

27. The Company maintained that a 750 Megawatt coal plant could not be bid by an independent power producer at a lower cost than Comanche 3 because, among other things, IPPs would have higher capital costs than a utility and may incur substantial difficulty and expense in obtaining water rights and environmental permits for a greenfield coal site. Left unanswered is how these concerns go away going forward; that is, these same costs and difficulties make new coal plants less likely to be chosen in the RFP process than other resources, even when the Company is not offering a self-build alternative. According to Company witness Prager:

> We believe that there [are] significant challenges to permitting a [coal] facility like this under any circumstance. The experience of other companies throughout the country in permitting coal-fired power plants has been -- especially recently, one [of] great difficulty[.] [W]e've seen even over the last two weeks, several coal-fired power plant proposals be delayed as a result of permitting delays, primarily as a result of challenges brought by the environmental community.[43]

28. Imputation of a carbon tax makes the selection of such a coal resource still less likely.[44] Working up a coal bid takes substantial time, effort and money; many IPPs may choose not to bid for these reasons alone, if not for the capital cost, water, and environmental issues discussed above. By accepting the imputed carbon tax, the Commission imposes yet another reason not to bid – an artificial cost decreasing the likelihood of a winning bid.

29. No doubt many parties and non-parties to this case are content with the prospect that more coal plants are not likely to be built in Colorado as a consequence of the imputed

[43] Vol. 14, p.109. (Parentheticals added to correct for obvious mistakes in the transcript.)

[44] Company witness David Eves agreed that, all else equal, the adding of the $6-per-ton carbon tax imputation will make it less likely that the Company will receive coal bids even if Comanche 3 is approved. Transcript, Vol. 1, pp.144-45.

carbon tax. In my view, ratepayers who will have to pay more for natural gas or other resources than coal are disserved by imposition of an environmental tax by a Commission acting wholly outside legitimate process and its delegated authority. The state legislature, Congress, or an environmental agency may impose this cost; it is not our call to make.

30. There is also the matter that the carbon tax violates three of the Commission's LCP rules, and no party has requested a waiver of any rules as part of the carbon tax issue. Rule 3610(d) provides that each utility's written bidding policy must "ensure that bids are solicited and evaluated in a fair and reasonable manner." Rule 3610(f) states that, "[i]n selecting its final resource plan, the utility's objective shall be to minimize the net present value of rate impacts, consistent with reliability considerations and with financial and development risks."[45] Bids are not evaluated in a fair and reasonable manner when they are subject to an arbitrary penalty,[46] in this case the imputed carbon tax. Likewise, the end result portfolio is not based on the objective of minimizing the net present value of rate impacts when certain resources are handicapped with artificial costs. Finally, there is the requirement under Rule 3613(c) that the record contain sufficient evidence for the Commission to approve components of the utility's proposed RFP, "such as the proposed evaluation criteria." As noted above, the carbon tax penalty in the proposed evaluation criteria is based on speculative and incompetent evidence, and thus not supported by the record.

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[45] Rule 3610(f) goes on to state: "The utility shall consider renewable resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases; as a part of its bid solicitation and evaluation process. Further, the utility shall grant a preference to such resources where cost and reliability considerations are equal." However, this does not supplant the objective to minimize the net present value of rate impacts.

[46] *See* Footnote 41, *supra*.

31. This does not mean that I would follow a least cost path to the exclusion of all environmental considerations. We have the statutory command (C.R.S. § 40-2-123) that we fully consider renewable resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases. In my view, we more than comply with this mandate by agreeing to a number of controls and technologies that are not necessarily part of a least cost plan, including tens of millions of dollars to be spent on additional environmental controls on Comanche 1 and 2 (to control NOX, SOX, and mercury at levels below that required by existing environmental laws and regulations); agreeing to include wind levels of up to 15% penetration without having fully comprehensive wind studies completed to determine ancillary costs; and agreeing to a Renewable Energy Credit at a reasonable level.

E. Amount of the Renewable Energy Credit

Facts are stubborn, but statistics are more pliable - Mark Twain

32. The Renewable Energy Credit (REC) decreases the cost of qualifying renewable energy relative to non-renewable resources. While I do believe passage of Amendment 37 justifies establishing a REC amount, that amount must be based on relevant evidence. The amount proposed in the Agreement – $8.75/MWh – is grossly inflated by one irrelevant data point, and so it should be rejected.

33. The REC amount I would adopt would be based on the only evidence in the record relating to wholesale energy credits, because the REC in this case concerns only wholesale transactions. There were three data points submitted on wholesale transactions:

$6/MWh, 2.75/MWh, and 1.50/MWh. The average of those three is $3.42/MWh, and that is the amount I would adopt. The only other evidence submitted that the REC should be higher – $40/MWh according to a *website*[47] – related to retail, not wholesale credits, so it is irrelevant. In arriving at $8.75/MWh – a figure more than twice the average of the three wholesale data points – the parties must have given significant weight to the $40 figure. When there are only four data points, and one is not only almost seven times greater than the second-largest value but also irrelevant to the matter at hand, that data point should be rejected.

34. We have no expertise regarding RECs, and there is no market currently established for RECs in Colorado. Given the paucity of actual data points, we should rely only on relevant evidence.[48]

F. Amount To Be Spent On Demand Side Management Over The Next Ten Years

Experience teaches us to be most on our guard to protect liberty when the government's purposes are beneficent - Louis Brandeis

35. The proposal for 320 Megawatts of DSM over 10 years, at a nominal cost of $287 million (present value of $196 million), is a significant departure from the LCP rules. Public Service Company witness Debra Sundin testified that its much more limited rebuttal proposal (150 MW over 5 years for present value cost of $96 million) would likely have DSM resources

[47] Beyond the other problems highlighted above, a witness' hearsay testimony based on reading a website should be given little confidence.

[48] Again, by combining the $9/ton escalating carbon tax imputation with the $8.75/MWh credit, bids are not evaluated in a fair and reasonable manner because they are subject to arbitrary penalties. And the end result portfolio is not based on the objective of minimizing the net present value of rate impacts. So the inflated REC value violates Commission Rules 3610(b) and (f), and should not be approved.

that do not meet the net present value of rate impacts test[49] – in other words, the rates of all customers not taking advantage of the resources increase. Logically, a doubling of the rebuttal proposal results in all those extra resources not meeting the NPVRI test.

36. There are important policy reasons to oppose such an expanded DSM program. Most troubling is that it represents a regressive tax on poor ratepayers. Ms. Sundin testified that roughly only 40,000 residential customers (out of one million) take advantage of existing programs; this amounts to a participation rate of 4 percent.[50] This low residential participation rate almost certainly will continue with the expanded DSM programs, because to achieve the energy savings contemplated in the Settlement Agreement the programs must concentrate on larger energy users such as commercial and industrial customers. In practice, low or moderate-income people end up subsidizing[51] more wealthy residential and commercial ratepayers who can afford more efficient appliances, fluorescent lights, and other energy-saving devices. And many of these more wealthy ratepayers would have bought the more efficient appliance or light bulb anyway, meaning they are given a "free ride" from other ratepayers.

37. There also is a legal issue: whether the proposed DSM program violates Colorado law because of intra- and inter-class subsidies. While C.R.S. § 40-2-123 indicates that the Commission "shall consider utility investments in energy efficiency to be an acceptable use of ratepayer moneys," § 40-3-106(1)(a) holds:

[49] Transcript, Vol. 7, pp. 131, 132, 135. Ms. Sundin indicated that, although the Company did not provide any evidence in the record as to whether the 150-megawatt rebuttal proposal would meet the net present value rate impact standard, such a result is unlikely.

[50] Transcript, Vol. 7, p. 137. The actual number of Public Service Company residential customers is 1.27 million.

[51] In response to the question, "[a]ll the other customers who are not participating are essentially subsidizing that program for the customers who do participate?," Ms. Sundin answered: "From a financial standpoint, yes, they do." Transcript, Vol. 7, p. 137.

> [N]o public utility, as to rates, charges, service or facilities, or in any other respect, shall make or grant any preference or advantage to any corporation or person or subject any corporation or person to any prejudice or disadvantage. No public utility shall establish or maintain any unreasonable difference as to rates, charges service, facilities or, in any respect, either between localities or as between any class of service.

As noted by former Chairman Gifford's dissent in Decision No. C00-1057 (Docket No. 00A-008E, Sept. 26, 2000) at pages 44-45:

> The first sentence absolutely prohibits granting *any* preference within a rate class. The second sentence prohibits unreasonable differences between classes of service. DSM undeniably results in prohibited preferences within a rate class. It likewise causes unreasonable differences between rate classes because, to even begin to succeed, DSM must be heavily weighted toward industrial and large commercial customers.

While § 40-2-123 was enacted subsequent to that decision, it is not clear that such legislation expresses the legislature's "manifest intent" to override the prohibition against intra-class and unreasonable inter-class subsidies. *See* C.R.S. § 2-4-205. Allowing DSM above that which meets the NPVRI test results in intra-class rate subsidization (and unreasonable inter-class subsidies), just as it did in September 2000.

38. I do not advocate doing away with DSM; rather, I would allow DSM that meets the minimization of net present value rate impact standard. Company witness Debra Sundin testified that the ongoing "Savers Switch" program would meet this standard[52] because it benefits all ratepayers, i.e., it reduces customer rates whether or not they participate in the program. This obviates policy and legal concerns over intra- and inter-class subsidies, because there are none. Savers Switch works precisely because it reduces demand during high cost peak periods of generation; other DSM programs can increase the rates of all customers who do not participate. We won't know which programs meet the standard unless they are competitively

[52] Transcript, Vol. 7, p. 133.

bid; the DSM Settlement proposal eliminates this possibility in favor of Company expenditures of $287 million over ten years, at ratepayer expense.

39. We are told that the increased DSM expenditures will only cost the average residential ratepayer five cents per megawatt hour, but this is misleading. The five cents represents the difference between the settlement proposal and Public Service Company's rebuttal proposal, which the Company admitted would constitute a set aside[53] and almost certainly would not comply with NPVRI test. The actual cost of not complying with the NPVRI test is unknown (the company did not perform that analysis), but it is certain to be much higher than five cents per megawatt hour.

40. The suggestion that the Settlement Agreement results in the lowest cost resource plan is even more misleading. The Agreement manufactures a "least cost" result by failing to compare the cost of the expanded DSM proposal with the NPVRI outcome that would have been achieved via competitive bidding, and by artificially increasing the cost of carbon-emitting generation relative to other resources (and artificially decreasing the costs of those other resources).

G. Conclusion

41. This is a difficult case – factually, legally, politically. While I understand that much political pressure (from adequately represented groups) calls for accepting the Comprehensive Settlement Agreement without change, I firmly believe the facts, law and good public policy compels rejecting or modifying four of its provisions, as described above.

[53] Testimony of Fred Stoffel, Transcript, Vol. 5, p. 202.

42. Taxing is an easy business.[54] The Commission imposes a tax on ratepayers by artificially inflating the cost of certain resources and artificially deflating the cost of others; by allowing Public Service Company to spend and recover almost $300 million dollars on programs from which ninety-six percent of residential customers historically have not partaken; and by allowing advanced recovery of non-used and useful plant costs when it has not been justified by competent evidence in the record. These are taxes that are imposed without vote or adequate representation; they were agreed to by parties, not ratepayers.

43. On a positive note, I do think ratepayers will benefit from the Agreement.[55] Public Service Company provided a cost-benefit analysis demonstrating that ratepayers stand to benefit from PSCO building, owning and operating a 750 MW coal plant. In virtually all least cost planning assumptions ratepayers are better off, to the tune of hundreds of millions of dollars, if the Comanche 3 plant is built versus if it is not built. This is because of a host of factors, most notably the low cost of coal versus the high cost of running natural gas-fired plants, the cost efficiencies of constructing and operating Comanche 3 at a brownfield site, the huge cost of delay (again in the hundreds of millions) if the Commission waited one or two years to see whether a competitive acquisition process for a baseload plant yields a better result; and the environmental cost and permitting efficiencies associated with cleaning up Comanche units 1 & 2 while building Comanche 3 with state of the art environmental controls.

[54] Edmund Burke. The full quote is: “Taxing is an easy business. Any projector can contrive new compositions, any bungler can add to the old.”

[55] To be clear, I believe ratepayers would benefit to a much greater extent if the Commission rejected or modified the four objectionable provisions as described above.

44. Going forward, the Commission needs to address how to evaluate utility self-build versus competitive acquisition of baseload resources so we don't encounter the delay issue again, which in my view unfairly penalizes competitive bidders. We also need to create a regulatory environment that does not artificially discourage independent power producers from bidding on large baseload projects, as dictated by the economic interests of ratepayers.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

CHAIRMAN GREGORY E. SOPKIN

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Chairman

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

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2003 LEAST-COST RESOURCE PLAN	))))	**Docket No. 04A-214E**
IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER APPROVING A REGULATORY PLAN TO SUPPORT THE COMPANY'S 2003 LEAST-COST RESOURCE PLAN	))))))	**Docket No. 04A-215E**
IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE COMANCHE UNIT 3 GENERATION FACILITY	)))))	**Docket No. 04A-216E**

COMPREHENSIVE SETTLEMENT AGREEMENT

December 3, 2004

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PARTIES TO THIS COMPREHENSIVE SETTLEMENT

Public Service Company of Colorado, the Staff of the Colorado Public Utilities Commission (“Staff”), the Colorado Office of Consumer Counsel (“OCC”), the Colorado Energy Consumers Group,[1] the Colorado Governor’s Office of Energy Management and Conservation, Western Resource Advocates, Colorado Coalition for New Energy Technologies, Southwest Energy Efficiency Project, Environment Colorado, Colorado Renewable Energy Society, the City and County of Denver, and Tri-State Generation & Transmission Association, Inc. (collectively, the “Parties”) hereby enter into this Comprehensive Settlement Agreement.[2]

INTRODUCTION

On April 30, 2004 Public Service Company of Colorado (“Public Service” or the “Company”) filed with the Commission the Verified Application of Public Service Company of Colorado for Approval of its 2003 Least-Cost Resource Plan. With the application, the Company filed its Least-Cost Resource Plan (“LCP”) in four volumes: Volume 1 – Plan Summary; Volume 2 – Renewable Energy Request for Proposals; Volume 3 – All-Source Requests for Proposals; and Volume 4 –Technical Appendix.

[1] Although a part of the Colorado Energy Consumers Group, AARP does not join in this Comprehensive Settlement Agreement and takes no position with respect to whether it should be approved.

[2] The following intervenors have not signed this Comprehensive Settlement Agreement: Colorado Mining Association, Colorado Independent Energy Association; Calpine Corporation; CF&I Steel, LP; City of Boulder; Climax Molybdenum Company; North American Power Group, Ltd.; L S Power Associates, L.P.; Baca Green Energy; LLC, Prairie Wind Energy, LLC; Pacificorp; Sun Power, Inc.; Arkansas River Power Authority; Rocky Mountain Farmers Union; Aquila, Inc.; Yampa Valley Electric Association, Incorporated; Holy Cross Energy; and the Regents of the University of Colorado at Boulder. Some of these parties are still reviewing the Comprehensive Settlement Agreement and may join the settlement on or before the date of the evidentiary hearing scheduled for December 8, 2004.

The Company also filed the Motion of Public Service Company of Colorado for Waiver of the 250 MW Limit in LCP Rule 3610 (b) to Permit the Construction of Comanche Unit 3.

On April 30, 2004, Public Service also filed the Verified Application For an Order Granting to Public Service Company of Colorado a Certificate of Public Convenience and Necessity, with supporting testimony, to construct Comanche 3.[3] Further, on April 30, 2004, the Company filed a Verified Application, with supporting testimony, for an order approving a proposed regulatory plan to support the Company's 2003 Least-Cost Resource Plan. The Company filed motions to consolidate into one docket the three applications filed on April 30.

The Commission granted the Company's motions to consolidate the three applications, but severed consideration of the Renewable Energy Request for Proposals from this consolidated docket and addressed the Company's Renewable Energy RFP in Commission Docket No. 04A-325E.

On August 13, 2004, Public Service filed Supplemental Direct Testimony. On September 13, 2004, the Intervenors filed Answer Testimony. On October 18, 2004, Public Service filed Rebuttal Testimony and other parties filed Cross-Answer Testimony.

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[3] Comanche 3 shall be defined to mean a new coal-fired steam electric generating unit with a summer net dependable capacity of 750 MW, and a maximum gross heat input rate of approximately 7421 million Btu per hour as set forth in the preconstruction air permit application, and to be located at the existing Comanche Station near Pueblo, Colorado. Public Service shall operate Comanche 3 but may co-own the unit with other entities. "Comanche 1" shall mean an existing coal-fired steam generating unit with a summer net dependable capacity of 325 MW. "Comanche 2" shall mean an existing coal-fired steam generating unit with a summer net dependable capacity of 335 MW. "Comanche Station" shall mean Comanche 1, Comanche 2 and Comanche 3, collectively.

Hearings were held from November 1 through November 17, 2004. At the hearing on November 18, the Company requested suspension of hearings to afford time to negotiate settlement of the contested issues in this consolidated docket. By Decision No. C04-1409 the Commission agreed to continue the hearings until December 8, 2004.

SETTLEMENT WITH CONCERNED ENVIRONMENTAL AND COMMUNITY PARTIES

Public Service conducted two separate sets of settlement discussions. The first set of discussions was among Public Service and national, regional, and local environmental and community groups who had expressed concerns about the public health and environmental impacts that will result from Comanche 3. These groups are collectively referred to as the "Concerned Environmental and Community Parties" or "CECP". Some of the CECP groups are intervening parties in this consolidated Commission docket; others spoke at the Commission's public statement hearings; others have not presented their views directly to the Commission.

Public Service reached settlement with CECP. The "CECP Settlement" is attached to this Comprehensive Settlement Agreement as Attachment A.[4] In consideration for the emission reductions and other provisions of the CECP Settlement, the Concerned Environmental and Community Parties agreed not to initiate, fund or participate in any formal administrative or legal action to oppose or knowingly impede the permitting or approval of those activities necessary for the construction and

[4] This Comprehensive Settlement Agreement generally describes the obligations of CECP. To the extent there are any inconsistencies between the general descriptions of CECP obligations in this Comprehensive Settlement Agreement and the CECP Settlement, the CECP Settlement shall control.

operation of Comanche 3 that are listed in Section 16 of the CECP Settlement. The CECP Settlement should mitigate but may not eliminate the risk of delay in the air permitting and construction of Comanche 3. Delay in obtaining the air permit for Comanche 3 would erode the economic benefits provided by Comanche 3 to Public Service's customers.

Pursuant to Section 17(A) of the CECP Settlement, Public Service agreed to seek Commission approval for the commitments in Sections 3, 4, 5, 6, 7, 8, 12, 14 and 15 of the CECP Settlement, as part of the Commission order on the Company's 2003 Least Cost Plan. Section 17(A) states that, if the Commission does not approve in full the Company undertaking the commitments in these sections of the CECP Settlement, or if a Commission order significantly impedes implementation of any of the commitments under the CECP Settlement, or if the Commission Order approving such commitments is reversed on judicial appeal in any significant respect, Public Service's and CECP's obligations under the CECP Settlement are terminated.

Since Public Service and its customers derive significant benefits from the CECP Settlement, termination of the CECP Settlement should be avoided. Public Service and the Parties to this Comprehensive Settlement Agreement agree that it is in the public interest for the Commission to approve Public Service undertaking the commitments set forth in Sections 3, 4, 5, 6, 7, 8, 12, 14 and 15 of the CECP Settlement. These provisions are referenced in this Comprehensive Settlement Agreement. Public Service and the Parties to this Comprehensive Settlement Agreement further request that the Commission not issue an order that would significantly impede the implementation of any of the commitments set forth in the CECP Settlement. Notwithstanding the foregoing, unless a Party to this Comprehensive Settlement Agreement is also a signatory to the CECP Settlement, a Party to this Comprehensive Settlement Agreement is not bound by the provisions in the CECP Settlement. The Parties to this Comprehensive Settlement Agreement have attempted to make the Comprehensive Settlement Agreement and the CECP Settlement consistent with each other in all material respects, and it is the Parties' intent and recommendation that the two agreements should be interpreted as consistent with each other. However, Public Service is not asking for the Commission to agree to the CECP Settlement in its entirety because it addresses some issues that are beyond the scope of this proceeding. Public Service and the Parties to this Comprehensive Settlement Agreement are requesting only that the Commission approve this Comprehensive Settlement Agreement.

COMPREHENSIVE SETTLEMENT WITH PARTIES TO CONSOLIDATED COMMISSION DOCKET

The second set of settlement discussions was held among Public Service and some of the intervening parties in this consolidated docket. These settlement negotiations have resulted in this Comprehensive Settlement Agreement.

COMPREHENSIVE SETTLEMENT

The Parties to this Comprehensive Settlement Agreement hereby agree to the following resolution of the contested issues in this consolidated docket.

CPCN for Comanche 3

1. The Commission should grant the Company a Certificate of Public Convenience and Necessity ("CPCN") to construct Comanche 3 as a supercritical pulverized coal-fired steam electric generating unit. The description of Comanche 3 is set forth in the testimony and exhibits filed by the Company with its Application for a CPCN. The CPCN granted by the Commission should also grant the Company permission to install both the new emission controls to the existing generating units Comanche 1 and Comanche 2 that are discussed in the Company's LCP and testimony and exhibits and the additional environmental controls that are discussed below in this Comprehensive Settlement Agreement. The construction authorized by this CPCN for Comanche 3 and the additional environmental controls for Comanche 1 and Comanche 2 shall be referred to collectively in this Comprehensive Settlement Agreement as the "Comanche Project."

2. Public Service has preexisting contractual commitments that require it to offer ownership shares in Comanche 3 to Intermountain Rural Electric Association and Holy Cross Energy. If both of these Colorado utilities agree to participate with Public Service in Comanche 3, Public Service's share of Comanche 3 would be approximately 500 MW. In its CPCN Application, Public Service requested a CPCN to construct a 750 MW Comanche 3 and to own 500 MW of Comanche 3. Negotiations between Public Service and Intermountain Rural Electric Association, and between Public Service and Holy Cross Energy, for participation in Comanche 3 have not yet been completed.

3. Due to the expected benefits from Comanche 3, the Parties agree that the Commission should grant Public Service a CPCN that will allow Public Service to

construct and own 750 MW of Comanche 3. Given Public Service's pre-existing contractual commitments to Intermountain Rural Electric Association and Holy Cross Energy, the Parties further agree that the Commission should approve, as part of the CPCN, a transfer by Public Service to Intermountain Rural Electric Association and to Holy Cross Energy of an ownership share of up to approximately 250 MW, but these transfer approvals shall be subject to the limitations set forth in Highly Confidential Attachment B to this Comprehensive Settlement Agreement. Should Public Service not be able to reach joint ownership terms and conditions with either Intermountain Rural Electric Association or Holy Cross Energy or both that comply with the limitations set forth in Highly Confidential Attachment B, then Public Service must file a separate application with the Commission under C.R.S. §40-5-105 if Public Service desires to transfer an ownership interest in Comanche 3 to the utility who refused to agree to ownership terms and conditions that comply with the limitations set forth in Highly Confidential Attachment B. Should Public Service desire to sell an ownership share in Comanche 3 to any entity other than Intermountain Rural Electric Association or Holy Cross Energy, Public Service must obtain Commission approval under C.R.S. §40-5-105.

4. In order to grant Public Service the CPCN set forth in this Comprehensive Settlement Agreement, the Parties recommend that the Commission grant Public Service's motion for a waiver of the 250 MW limit in Rule 3610 (b) of the Commission's Least-Cost Resource Planning Rules.

Additional Environmental Controls

5. The Company shall install lime spray dryers on both Comanche 1 and Comanche 2 as required by section 3 of the CECP Settlement. The cost of the lime spray dryer for Comanche 2 was already included within the cost estimates set forth in the Company's testimony and exhibits. The additional lime spray dryer for Comanche 1 is estimated to cost approximately $48 million ($2003).

6. Public Service shall comply with the monitoring, testing and emission limits for mercury set forth in section 7 of the CECP Settlement. The CECP Settlement establishes a process by which the Company will test mercury emissions at Comanche Station no later than 180 days after the initial startup of Comanche 3 and will provide its test results to the Colorado Department of Public Health and Environment ("CDPHE") and CECP. The CDPHE shall use the test results provided by the Company to determine the maximum level of mercury control for the Comanche Station that CDPHE considers to be cost-effective based on a dollar per pound of mercury removed. The mercury control limits determined by CDPHE to maximize cost-effective reductions for Comanche Station will be incorporated into the Title V operating permit. The mercury control technology is likely to be sorbent injection, unless a better control technology emerges. It is anticipated that Public Service will need to install, as it constructs the Comanche Project, mercury emission controls with an estimated capital cost of approximately $3 million ($2003). Public Service anticipates that the mercury emissions testing that it will perform for CDPHE will cost approximately $500,000 ($2004). Finally, Public Service anticipates that the mercury control level determined by CDPHE, as described above, will require Public Service to spend initially from $2 million to $5

million per year in the first year's operation and maintenance costs associated with the control technology, beginning no later than two years after the initial startup of Comanche 3. This annual operation and maintenance expense may increase with the escalation in the variable costs of the control technology or due to the establishment of laws or regulations that provide for more stringent mercury emissions limits than those determined by CDPHE as a result of the process set forth in the CECP Settlement.

7. All emission control equipment installed on Comanche 1, Comanche 2 and Comanche 3 shall be designed to comply with the specific emission limits, installation and compliance schedules, and other permit requirements set forth in sections 3, 4 ,5, 6, 7 and 8 of the CECP Settlement.

8. In addition to the specific additional environmental controls set forth in this Comprehensive Settlement Agreement, Public Service may be required by either CDPHE or the United States Environmental Protection Agency to incur additional expenditures in order to receive an air permit for Comanche 3.

9. The Parties agree that, except as provided later in this Comprehensive Settlement Agreement with respect to the Construction Cost Cap, the investments in environmental controls associated with the Comanche Project set forth in paragraphs 5 through 8 above are deemed prudent and are recoverable in rates. The Parties further agree that operation and maintenance expenses associated with the environmental controls set forth in paragraphs 5 through 8 above are recoverable in rates by Public Service to the extent the operation and maintenance expenses are prudently incurred.

10. Section 9 of the CECP Settlement sets forth additional covenants that address environmental mitigation in the Pueblo area. Public Service agrees that the

environmental mitigation covenants in section 9 of the CECP Settlement with respect to shredded car bodies at the Rocky Mountain Steel plant in Pueblo and the diesel school buses in the Pueblo area shall not be recoverable in rates.

11. The CECP Settlement also addresses in section 10 sustainable development activities for the Pueblo region, and in section 13 the consideration of innovative technologies. The Parties to this Comprehensive Settlement Agreement who are not signatories to the CECP Settlement are taking no position with respect to these covenants in the CECP Settlement. Further, the Parties to this Comprehensive Settlement Agreement request that the Commission take no action at this time as to the rate treatment that should be afforded in future rate proceedings to any costs incurred by the Company to comply with the sustainable development activities and with the consideration of innovative technologies required under the CECP Settlement.

Construction Cost Cap

12. In exchange for the compromises reflected in this Comprehensive Settlement Agreement, Public Service agrees that the construction costs for the Comanche Project that may be placed into its rate base shall be subject to a cap. Public Service shall be limited to placing into utility rate base the actual capital expenditures[5] for the Comanche Project that are equal to or below the Construction Cost Cap determined in accord with Highly Confidential Attachment C. The Parties agree that actual capital expenditures incurred by Public Service, up to and including the level set by this Construction Cost Cap, represent reasonable and prudent

[5] By "actual capital expenditures" the Parties mean the capital expenditures that are recorded in the Company's books and records under the FERC Uniform System of Accounts. Separate sub-accounts shall be established for the Comanche Project.

expenditures by Public Service that shall not be subject to challenge at the time that the Company seeks to place the Comanche Project into rate base, except to the extent a Party could establish that an expenditure resulted from fraud or deceit on the part of Public Service, its affiliates, or its contractors.

13. In addition to actual construction cost up to the Construction Cost Cap, Public Service shall be entitled to include in rate base, when a commercially-operational Comanche 3 is reflected in the test year of a Phase 1 rate proceeding, the Company's accumulated AFUDC[6] associated with the capital expenditures for the Comanche Project that are at or below the Construction Cost Cap.

14. By agreeing to the recovery of Comanche 3 construction costs that are at or below the Construction Cost Cap determined in accord with Highly Confidential Attachment C, Parties to this Comprehensive Settlement Agreement do not waive the right to challenge the recovery of replacement power costs that result from material delays in the commercial operation date of Comanche 3 due to imprudence.

15. The Company shall file progress reports with the Commission semi-annually, beginning June 1, 2005 and ending with the first report after Comanche 3 reaches commercial operation, regarding the progress of construction and the expected commercial operation date of Comanche 3. The progress reports shall contain the status of each vendor contract (including updated information on contracts under negotiation) and a narrative which summarizes bids received and the selection process employed for each vendor contract. The progress reports shall also set forth the force majeure clauses in each vendor contract and in any subcontract let by Utility

[6] The accumulated AFUDC must be set forth in the Company's books and records in a Comanche Project sub-account in accord with FERC Uniform System of Accounts.

Engineering Corporation or by Public Service. The progress reports shall provide the account balances for all Comanche Project expenditures.[7] The progress reports also shall include budgeted versus actual status with respect to the milestone payment schedule, differences in status between the projected and actual overall construction schedule and the status of on-going permit applications. Any material departure from the milestone payment schedule or the construction schedule will be accompanied by a narrative explaining the departure. Continuing property records shall be timely maintained and available for inspection. Finally, the progress reports shall list any material design or scope change orders. Public Service reserves the right to file bid and financial information under seal and to seek highly confidential protection for this information.

2003 Least-Cost Resource Plan and 2005 All-Source Solicitation

16. The Parties agree that the Company should use a planning reserve margin of 16%[8] for the 2003 LCP.[9]

17. For purposes of the 2003 LCP, Public Service agrees not to apply a balance sheet equalization factor or other imputed debt adjustment mechanism to the bids received.

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[7] The Comanche Project expenditures shall be set forth in the Company's books and records in Comanche Project sub-accounts in accord with FERC Uniform System of Accounts.

[8] The 16% is applied to the Company's "base" demand forecast (i.e. normal weather).

[9] When the term "2003 LCP" is used in covenants set forth in this Comprehensive Settlement Agreement, the Parties intend that the term shall include the Company's 2003 LCP as approved by the Commission in this docket, all resource solicitations that are conducted under the Company's approved 2003 LCP, the implementation of any contingency plan that may be required under the 2003 LCP, and any amendments to the 2003 LCP that the Company may file.

18. As required by section 12 of the CECP Settlement and in consideration of the potential incurrence of future costs due to greenhouse gas regulation (e.g., carbon dioxide taxes or allowance costs) during the 30 year Planning Period of the 2003 LCP, the Parties agree that all evaluations of resources acquired under the 2003 LCP should include imputation of CO_2 costs of $9/ton beginning in 2010 and escalating at 2.5% per year beginning in 2011 and continuing over the planning life of the resource. The imputed cost of CO_2 shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation processes. In evaluating bids during the initial economic screening, Public Service shall reflect the costs associated with the CO_2 proxy cost as a dollar per MWh variable operating cost. In the dynamic portfolio optimization modeling, the CO_2 proxy cost shall be applied to all existing and new resources as a $/MWh variable operating cost affecting resource dispatch. For any CO_2 emitting resource, the variable $/MWh CO_2 cost of a resource shall be calculated using the formula set forth in Section 12(C) of the CECP Settlement, which is hereby incorporated by reference.

19. In accord with section 15(E) of the CECP Settlement and in recognition of the potential future value of renewable energy credits ("RECs") provided to Public Service, particularly after the passage of 2004 Colorado Ballot Initiative Amendment 37, the Company shall include a REC value of $8.75/MWh for all renewable resources bid into solicitations under the 2003 LCP, with the exception of the Renewable Energy RFP issued August 17, 2004. To qualify for the REC value, the renewable energy bid must meet the definition of "Eligible Renewable Energy Resource" under Amendment 37, as that definition may be updated by the Colorado Legislature by the time the bids are due

in response to the 2005 All-Source RFP or by the time the bids are due in response to any other solicitation conducted under the 2003 LCP. The REC value shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation process. Public Service shall apply the REC value to renewable resource bids for all operating years of the renewable energy project from 2006 onward. The Renewable Energy Credit will not escalate in value over the Planning Period used in the 2003 LCP.

20. As required by CECP Settlement sections 15(A) and 15(B), Public Service shall accelerate and complete those components of the wind ancillary service cost study required by the Commission in Docket No. 04A-325E that are necessary to obtain projections of ancillary service costs for nameplate wind penetration levels of 15% of Public Service's system peak demand. For purposes of the study, the 15% wind penetration level shall be based on Public Service's 2007 peak demand forecast or Public Service's best available peak demand forecast for 2007 at the commencement of the study. These necessary components of the study shall be completed in time to evaluate wind resource bids submitted in response to the 2005 All Source RFP. Public Service shall accept wind bids in response to solicitations under the 2003 LCP up to a 15% penetration level, so long as the wind bids are part of Public Service's least cost resource portfolio. In the 2003 LCP, due to concerns over potential operational impacts, the Company will not be required to select resources that would result in a greater than 15% penetration level of intermittent resources on the Public Service system. For this purpose, the 15% wind penetration level shall be based on Public Service's peak demand forecast used to determine resource need and acquisition at the time of the bid

evaluations and shall be calculated based on the year in which the wind resource would be projected to come on-line. Nothing in this paragraph shall alter the $2.50/MWh ancillary service costs to be ascribed to intermittent resources that are bid in response to the Company's Renewable Energy RFP issued on August 17, 2004; the ancillary service costs ascribed to the Renewable Energy RFP bids shall be governed by the Commission's orders in Docket No. 04A-325E.

21. Public Service shall use a capacity value of wind generation resources equal to 10% of nameplate capacity for existing wind generation and in evaluating the wind bids submitted in response to solicitations conducted under the 2003 LCP.

22. Public Service shall remove from the Model Power Purchase Agreement provided with the 2005 All-Source RFPs and other solicitations under the 2003 LCP an opportunity for bidders to sell up to ten megawatts of Excess Capacity to Public Service beyond the level of capacity specified in the bid.

23. The Parties agree that, when assessing supplier concentration and parent company financial strength of bidders in the 2003 LCP, the evaluation will focus on an assessment of the bidder's ability to perform the obligations of the project under a potential purchase power agreement.

Additional Resource Planning Studies

24. Public Service, Staff and OCC shall jointly work to develop a study scope and study methodology, and to identify appropriate study model(s), to perform a probabilistic assessment of the appropriate reserve margin for the Public Service system that includes consideration of the following:

a. Resources acquired in the Renewable Energy RFP, the 2005 All-Source RFP, plus Comanche 3;

b. Weather related load variability; and

c. Planned and unplanned generation and transmission outages.

Public Service shall use its best efforts to collect information from all electric systems within the TOT-constrained area of Eastern Colorado and to obtain commercially-available Loss of Load Probability (LOLP) models that have the capability to properly represent both 1) the transmission limitations of the TOT-constrained area and 2) the reliability support that the different electric systems provide to each other. If Public Service is able to obtain the data and software necessary to conduct this study, Public Service shall study the full TOT-constrained area of Eastern Colorado. If Public Service, Staff and OCC reach consensus on the study scope, methodology, and appropriate computer models, then Public Service, Staff and OCC shall rely on the study results to develop their individual recommendations for the reserve margin in Pubic Service's next resource plan. If Public Service, Staff and OCC are unable to reach consensus on the study scope, methodology, or appropriate computer models that would produce a meaningful study of the TOT-constrained area of Eastern Colorado, within the limitations of available data and modeling software, all Parties are free to advocate any position in the next Public Service resource plan.

25. In accord with section 15(D) of the CECP Settlement, Public Service shall perform an Effective Load Carrying Capability study on its system as a means for determining the capacity value of wind generation resources. The study shall consider the uncertainty or variability of hourly wind generation patterns from year-to-year and

the combined effects of diverse wind farm locations. Public Service shall file the study with the Commission and provide copies to the Parties by November 1, 2006. Public Service agrees to advocate in future Commission proceedings that the reliability contribution or capacity value of wind generation resources should be based upon a method that incorporates consideration of reliability contribution in all hours of the year and to propose recommendations for ascribing capacity value to existing and new wind generation resources. Public Service shall solicit participation of industry experts, Staff, OCC and other interested parties with Public Service personnel on a technical review committee with the intent of incorporating their specific interest and knowledge base into the study. If Public Service claims the information in such report is confidential, any member of the technical review committee or any organization listed in Section 1 to the CECP Settlement shall be allowed to review such information after signing a reasonable confidentiality agreement that ensures that commercially sensitive or trade secret information is protected. Members of the technical review committee shall be afforded access to confidential information of entities other than Public Service only upon the execution of non-disclosure agreements acceptable to the owner of the Confidential Information. The Parties to this Comprehensive Settlement Agreement, other than Public Service, reserve their rights to advocate for a different method for determining wind capacity value.

26. In accord with section 15(C) of the CECP Settlement, if Public Service selects cost-effective wind generation resources in response to the Renewable Energy RFP and All-Source Solicitations of the 2003 LCP that increase nameplate wind generation on its system above 720 MW, Public Service agrees to perform an

additional ancillary service cost study to obtain projections of ancillary service costs at a 20% penetration level. This 20% wind penetration study shall be used to inform resource solicitations subsequent to the solicitations conducted under the 2003 LCP.

27. Public Service agrees to conduct and present with its CPCN application for the transmission facilities required by Comanche 3 the following two studies. Public Service will evaluate the specific 230 kV alternative for the Comanche 3 transmission system outlined by Mr. Dominguez in his Answer Testimony in this consolidated docket. Further, as requested by Staff witness Mr. Dominguez, Public Service will evaluate methods to reduce transmission noise levels to 50 db(A) for the 345 kV double circuit Comanche-Midway-Daniels Park facility proposed in Volume 4 of the Company's LCP. By agreeing to conduct these studies, Public Service is not agreeing that these alternatives will be the transmission facilities that Public Service proposes to construct or for which Public Service requests a CPCN. The Parties reserve their rights to comment upon Mr. Dominguez's alternatives to protect their respective interests.

28. Under the Stipulation Between the Staff of the Colorado Public Utilities Commission and Public Service Company of Colorado with Respect to Wind Studies, as modified by the Commission in Docket No. 04A-325E by Decision No. C04-0994 (August 24, 2004), Public Service is obligated to perform power flow and stability analyses, using 2007 power flow cases, of the portfolio of resources selected by the Company in response to the Renewable Energy RFP. Public Service shall invite neighboring transmission owners, through the auspices of the Colorado Coordinated Planning Group, to participate in these studies.

29. In order to increase public information about wind generation facility operations, Public Service agrees to request permission from wind energy sellers to publicly disclose historic production data on a 2-minute interval basis. To the degree that such permission is obtained, Public Service agrees to make such information available upon request. Such information will be provided on a historic basis only.

Demand-Side Management

30. In order to achieve energy efficiency to provide a hedge against volatile gas prices and against uncertain future emission regulation, in order to reduce total system costs, and in accord with section 14 of the CECP Settlement, Public Service shall use its best efforts to acquire, on average, 40 MW of demand reduction and 100 GWh of energy savings per year from cost-effective Demand-Side Management ("DSM") programs over the period beginning January 1, 2006 and ending December 31, 2013, so that by January 1, 2014 the Company will have achieved a cumulative level of 320 MW of total demand reduction and 800 GWh of annual energy savings. Notwithstanding the foregoing, Public Service's actual annual demand reductions and energy savings during this period may vary from these annual averages. The Company shall expend $196 million (2005 dollars) to meet such demand reductions and energy savings unless these demand reductions and energy savings are achieved with a lower level of expenditures. The DSM demand reductions and energy savings required by this paragraph shall include the demand reductions and energy savings achieved by Public Service through bidding under the 2003 LCP. The Company shall strive to develop and implement a set of DSM programs that give all classes of customers an opportunity to participate. As part of this effort, the Company will attempt to develop for

residential and commercial customers some programs that concentrate on reduction in peak demand and some programs that concentrate on reduction of energy usage. All DSM programs implemented under this Comprehensive Settlement Agreement, outside of bidding under the 2003 LCP, shall be required to pass the Total Resource Cost test. All DSM programs selected in the 2005 All-Source Evaluation will be part of the portfolio that minimizes the net present value of rate impacts.

31. The Company shall perform a market study to determine, generally, levels of efficiency available for various customer classes and the costs associated with such measures, and whether such levels of DSM are cost-effective and available in Colorado. Public Service agrees to involve other stakeholders in the design of the market study and the review of the contractor summary results. The market study shall not exceed $2 million in cost. Public Service shall complete the market study as expeditiously as practicable, but no later than March 31, 2006.

32. Public Service further commits to conduct program-specific market and load research and ongoing measurement and verification for each DSM measure as appropriate, ranging from random audits to project-based reviews for the more customized measures. Public Service will conduct an impact and process evaluation that assesses the amount of energy and demand savings from each program and evaluates the functional efficiency and customer satisfaction with each program. Public Service will spend up to an additional $2 million on these evaluation efforts. The $4 million spent on the market study and the evaluation efforts shall be included in the $196 million cap and shall be recoverable through the Demand Side Management Cost Adjustment ("DSMCA") clause.

33. Public Service shall be entitled to continue to fully recover its expenses and investment associated with existing DSM programs under the Company's 1999 Integrated Resource Plan under the terms and conditions of the Company's current DSMCA, which include a five year amortization period for DSM investment.

34. For the DSM programs contemplated by this Comprehensive Settlement Agreement, Public Service shall be entitled to fully recover its expenses and investment associated with these new programs under the terms and conditions of the Company's current DSMCA, except that the Company's investment in DSM measures shall be amortized over an 8 year period instead of a 5 year period. All DSM investments associated with contracts signed after December 31, 2005 shall be considered to be investments subject to the 8 year amortization period. Further, the Company shall be entitled to make an out-of-period adjustment in its 2006 rate case filing to capture the annualized effect of incremental increases in internal labor, benefits and other employee-related costs associated with implementing this expanded DSM program through 2006. The Company shall include no more than 18 full-time-equivalent employees in this out-of-period adjustment. These incremental labor and employee-related costs shall be included in the $196 million cap discussed in prior paragraphs.

35. Within three months of completing the market study described in paragraph 31 above, but no later than July 1, 2006, the Company shall file an application with the Commission to open a docket to address the provision of DSM by Public Service above and beyond the levels provided by existing programs and by this

Comprehensive Settlement Agreement.[10] The Company acknowledges that in the DSM docket initiated pursuant to this paragraph, the Commission may examine for future DSM programs beyond the levels set forth in this Comprehensive Settlement Agreement, among other issues, 1) whether the Company's expenses should be recovered through a rider and 2) the appropriate amortization period for recovery of DSM investment.

36. Public Service shall file with the Commission with its annual DSMCA filing a report on the DSM expenditures, energy savings, and peak demand reduction achieved by the programs for the past year. Public Service shall also file with the Commission with its annual DSMCA filing the results of the impact and process evaluations[11] that were conducted in the past year.

37. Public Service shall establish and maintain a DSM working group that shall meet at least twice a year. The DSM working group shall be open to all interested persons and shall provide input to Public Service in DSM program design, analysis and other issues relevant to helping the Company meet or exceed the minimum energy savings and peak demand reduction levels. Public Service shall provide to the members of the DSM working group copies of all DSM filings it makes with the Commission.

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[10] The Company has agreed in section 14(D) of the CECP Settlement to advocate in the subsequent Commission DSM proceedings, among other things, for use of the Total Resource Cost test and for financial incentives for Company acquisition of DSM. The Parties to this Comprehensive Settlement Agreement who are not signatories to the CECP Settlement are not bound by these terms of the CECP Settlement and fully reserve their rights to advocate for their interests in the subsequent DSM docket.

[11] Public Service shall conduct impact and process evaluations at the conclusion of each program.

38. The Parties do not agree among themselves as to whether the Commission must grant the Company a waiver from the Commission's Least-Cost Resource Planning Rules to accomplish the DSM commitments set forth in this Comprehensive Settlement Agreement. The Parties are not asking the Commission for a specific ruling on whether a waiver is required. However, to the extent that a waiver is required, the Parties agree that the public interest would be served by the Commission granting such a waiver.

Impact of Settlement on Public Service's 2003 LCP

39. Public Service represents that it has modeled the economic impact of the provisions of this Comprehensive Settlement Agreement on the Company's screening analyses presented in the Company's filed 2003 Least-Cost Resource Plan, with a variety of updated modeling assumptions including the use of the price for natural gas used in the Renewable Energy RFP bid evaluation.[12] Public Service's report discussing the assumptions used for each model run and the results of these model runs is attached as Attachment D. Public Service represents that the model runs show the impact of this Comprehensive Settlement Agreement, referred to as the "Settlement Case" in comparison to both the case proposed in the Company's October 18, 2004 rebuttal testimony and to updated generic screening analyses.[13] In general, Public Service represents that these runs demonstrate the following aspects of the Settlement Case:

[12] The gas price used in the Renewable Energy RFP bid evaluation is based upon on combination of four different long-term gas price forecasts: CERA, PIRA, EIA, and NYMEX.

[13] A description of the updates made to the Company's screening analyses is set forth in Attachment D.

a. Even with the additional environmental controls, the inclusion of higher CO_2 proxy costs, and increased DSM required by this Comprehensive Settlement Agreement, Comanche 3 is still chosen as part of the Least- Cost Resource Plan.

b. An additional coal resource could be selected in the 2005 All-Source RFP Evaluation as part of the Least-Cost Resource Plan.

c. Additional gas-fired resources could be selected in the 2005 All-Source RFP Evaluation as part of the Least-Cost Resource Plan.

d. Additional wind resources priced without the benefit of the federal production tax credit could be selected in the 2005 All-Source RFP Evaluation as part of the Least-Cost Resource Plan.

e. The Comprehensive Settlement Agreement, including DSM, produces a net present value reduction of revenue requirements of approximately $90 million compared to the Company's October 18, 2004 rebuttal case and between $500 million to $1.3 billion compared to the revised generic screening analyses. The Comprehensive Settlement Agreement, including DSM, results in a slight increase in the net present value of average rate impacts of approximately $0.05/MWh ($0.00005/kWh) compared to the Company's rebuttal case and a reduction in the net present value of average rate impacts of between $.58/MWh and $2.14/MWh compared to the revised generic screening analyses.

New LCP Rules

40. Concerns were expressed by many Parties to this docket about various provisions in the Commission's Least-Cost Planning Rules. The Parties agree that Public Service shall file a petition no later than September 1, 2005 requesting the

Commission to open a rulemaking docket to reexamine the LCP rules. Among other things, the petition shall request that the rulemaking proceeding should examine the following topics: 1) the competitive solicitation processes that should be used to acquire various types of resources; 2) how a utility rate-based generation facility can be fairly evaluated and compared against purchased power options; 3) the effects of purchased power contracts on utility balance sheets and income statements and how those effects can reasonably be addressed; 4) how cost impacts and cost recovery can be integrated into the resource planning and acquisition cycle; 5) whether the net present value of revenue requirements instead of net present value of rate impacts should be the test employed to select the least cost resource portfolio; 6) how future environmental regulatory risks should be taken into account; 7) the adequacy of the current public participation process, and 8) the appropriate cost-effectiveness test for DSM. Public Service shall not ask the Commission to reopen Rules 3602 and 3605 dealing with the applicability of the Commission's LCP Rules to cooperative electric associations and cooperative generation and transmission associations[14]

Regulatory Plan

41. The Company acknowledges that the Intervenors' willingness to resolve the cost recovery issues as set forth below is based upon the particular factual circumstances that have been presented in this consolidated docket. The Parties agree that the following compromises and agreements with respect to the Regulatory Plan shall have no precedential effect or significance, except as may be necessary to enforce

[14] Other Parties reserve their rights to seek to expand the scope of the LCP Rulemaking.

this Comprehensive Settlement Agreement or Commission Order approving this agreement.

42. The Company agrees to withdraw its request for the Least Cost Plan Adjustment Rider.

43. Public Service agrees that it shall not file an electric Phase 1 rate case prior to January 1, 2006.

44. The Parties recognize the Company's need to begin increasing its equity ratio, as calculated for financial reporting purposes, to 56% to offset the debt equivalent value of existing purchased power agreements and to improve the Company's overall financial strength. The Parties agree that, for purposes of the 2006 Phase 1 rate case, the actual regulatory capital structure,[15] including pro forma adjustments but excluding short-term debt, as of the earlier of the date on which a settlement of the 2006 Phase 1 rate case is executed or the first day of evidentiary hearings, shall be deemed reasonable and shall be used to determine the Company's 2006 Phase 1 rate case revenue requirement. The Parties understand that, depending upon the level of short-term debt on the Company's balance sheet as of the date the regulatory capital structure is determined, the equity ratio could exceed 56%. Public Service stipulates that, for purposes of the 2006 Phase 1 rate case, its proposed regulatory capital structure shall not exceed 60% equity. Public Service reserves the right to seek higher levels of equity in its regulatory capital structure in Phase I rate proceedings subsequent to the 2006 rate case. The Parties reserve their rights to take a position that reflects their respective interests at such time.

[15] In calculating its actual regulatory capital structure, Public Service shall use its most recently available month-end financial statement as the starting point.

45. The Parties agree that in any one or more Phase 1 rate proceedings that the Company may file between January 1, 2006 and the later of January 1, 2011 or five and one-half years after the Company secures an administratively final air permit for Comanche 3,[16] provided that the Company's actual capital structure used for regulatory purposes equals or exceeds 56 percent equity, the Company shall be entitled to the following treatment of Construction Work in Progress associated with the construction of Comanche 3, the installation of environmental controls on Comanche 1, 2, and 3, and related transmission investment ("Comanche CWIP"):

a. If on the earlier of the date on which a settlement of the Phase 1 rate case is executed or the first day of evidentiary hearings, the Company's senior unsecured debt rating from either Standard & Poor's or Moody's is below A- or its Moody's equivalent, the Company shall be permitted to include Comanche CWIP in ratebase without an AFUDC offset, calculated as of the end of the applicable test year;[17] and

b. If on the earlier of the date on which a settlement of the Phase 1 rate case is executed or the first day of evidentiary hearings, the Company's senior unsecured debt rating from either Standard & Poor's or Moody's is below BBB+ or its Moody's equivalent, the Company shall be permitted to make an out-of-period adjustment to include Comanche CWIP in rate base without an AFUDC offset, accrued during the

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[16] If construction at Comanche 3 is halted due to a legal challenge to the air permit filed after issuance or other force majeure event, the five and one half year period referenced in this Paragraph shall be extended day for day for so long as the construction is halted.

[17] Based upon Public Service's current estimates, for illustrative purposes only, the annual revenue requirement impact of including the Comanche CWIP balance as of year-end 2005 in rate base without an AFDUC offset would be $ 4,747,150. This amount would be included in the revenue requirement used to establish rates that would take effect on January 1, 2007, assuming Public Service files an electric rate case in Spring 2006.

period ending twelve months following the end of the test year upon which the Phase 1 filing is based.[18] The Parties acknowledge that the Company's Phase 1 filing will include the Company's best estimate of the Comanche CWIP balance as of the end of the twelve month period following the end of the applicable test year, which estimate may be revised from time to time up until 30 days prior to the first day of scheduled evidentiary hearings in the Phase 1 rate case.[19]

c. If Public Service's actual capital structure used for regulatory purposes does not equal or exceed 56%, or if Public Service's senior unsecured debt rating from both Standard & Poor's and Moody's is at or above A- or its Moody's equivalent, then the Parties reserve their rights to take a position with respect to Comanche CWIP that reflects their respective interests at such time. If the Company's senior unsecured debt rating from both Standard & Poor's and Moody's is BBB+ or its Moody's equivalent, then the Parties reserve their rights to take a position with respect to the Comanche CWIP pro forma adjustment discussed in Paragraph b that reflects their respective interests at such time.

46. Public Service reserves the right to seek additional regulatory relief associated with the construction of the Comanche Project or the impact of purchased power at any time, except that the Company agrees that it shall not seek a rider specific

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[18] Based upon Public Service's current estimates, for illustrative purposes only, the annual revenue requirement impact of including the Comanche CWIP balance as of year-end 2006 in rate base without an AFDUC offset would be $ 29,513,628. This amount would be included in the revenue requirement used to establish rates that would take effect on January 1, 2007, assuming Public Service files an electric rate case in Spring 2006.

[19] Any revised Comanche CWIP estimate shall be filed with the Commission and served on all parties with accompanying work papers with an attestation by an officer of the Company and the Company's contractors, including Utility Engineering Corporation.

to recovery of the financing costs of Comanche 3 and the Company shall not file an electric Phase 1 rate case prior to January 1, 2006. The Parties reserve their rights to take a position that reflects their respective interests with regard to such additional regulatory relief requests.

GENERAL TERMS AND CONDITIONS

This Comprehensive Settlement Agreement reflects compromise and settlement of all issues raised or that could have been raised in this consolidated docket. The Parties agree that Public Service's last stated position regarding its proposed 2003 Least Cost Resource Plan, whether presented by Public Service in the pre-filed Least Cost Plan volumes, its pre-filed direct, pre-filed supplemental direct, pre-filed rebuttal testimonies, or oral statements at the evidentiary hearing, should be approved by the Commission, subject to the provisions of this Comprehensive Settlement Agreement[20].

All Parties agree to support this Comprehensive Settlement Agreement. The Parties agree to join a motion that requests the Commission to approve this Comprehensive Settlement Agreement and to agree to all provisions of this Comprehensive Settlement Agreement that are binding upon the Parties of this agreement.

Unless otherwise specifically indicated, the provisions of this Comprehensive Settlement Agreement shall apply only to the Company's 2003 LCP. Unless otherwise specifically indicated, the provisions of this Comprehensive Settlement Agreement do not apply to any other Commission docket affecting Public Service or any other utility.

[20] The Intervenors' agreement in this regard should not be assumed to imply that the Intervenors necessarily support these positions or necessarily agree that such positions should be adopted in the future.

This Comprehensive Settlement Agreement is a negotiated compromise of issues and is broadly supported by Parties who include Public Service, independent energy providers, retail customers, other utilities, and public interest and environmental organizations. Nothing contained herein shall be deemed to constitute an admission or an acceptance by any party of any fact, principle, or position contained herein. Notwithstanding the foregoing, the Parties, by signing this Comprehensive Settlement Agreement and by joining the motion to approve this Comprehensive Settlement Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of these provisions.

This Comprehensive Settlement Agreement is to be treated as a complete package, not as a collection of separate agreements on discrete issues or proceedings. To accommodate the interests of different parties on diverse issues, the Parties acknowledge that changes, concessions, or compromises by a party or parties in one section of this Comprehensive Settlement Agreement necessitated changes, concessions, or compromises by other parties in other sections.

The Parties hereby agree that all pre-filed testimony and exhibits that have not already been admitted into evidence in this docket shall be admitted into evidence without cross-examination.

This Comprehensive Settlement Agreement shall not become effective until the issuance of a final Commission Order approving the Comprehensive Settlement Agreement, which Order does not contain any modification of the terms and conditions of this Comprehensive Settlement Agreement that is unacceptable to any of the Parties and which does not result in the termination of the CECP Settlement. In the event the

Commission modifies this Comprehensive Settlement Agreement in a manner unacceptable to any Party, that Party shall have the right to withdraw from this agreement and proceed to hearing on the issues that may be appropriately raised by that Party in this docket. The withdrawing Party shall notify the Commission and the Parties to this Comprehensive Settlement Agreement by e-mail within three business days of the Commission-ordered modification that the Party is withdrawing from the Comprehensive Settlement Agreement and that the Party is ready to proceed to hearing; the e-mail notice shall designate the precise issue or issues on which the Party desires to proceed to hearing (the "Hearing Notice").

The withdrawal of a Party shall not automatically terminate this Comprehensive Settlement Agreement as to the withdrawing Party or any other Party. However, within three business days of the date of the Hearing Notice from the first withdrawing Party, all Parties shall confer to arrive at a comprehensive list of issues that shall proceed to hearing and a list of issues that remain settled as a result of the first Party's withdrawal from this Comprehensive Settlement Agreement. Within five business days of the date of the Hearing Notice, the Parties shall file with the Commission a formal notice containing the list of issues that shall proceed to hearing and the list of issues that remain settled. The Parties who proceed to hearing shall have and be entitled to exercise all rights with respect to the issues that are heard that they would have had in the absence of this Comprehensive Settlement Agreement. Hearing shall be scheduled on all of the issues designated in the formal notice filed with the Commission as soon as practicable.

Due to the importance of the CECP Settlement to the timely implementation of the 2003 LCP, Public Service has agreed in the CECP Settlement that if the Commission order in this docket would result in the termination of the CECP Settlement, Public Service, and certain other Parties, shall jointly apply for rehearing, reargument and reconsideration of the Commission decision.[21] If Public Service applies for rehearing to comply with the CECP Settlement, the Parties agree that rehearing of the Commission decision and the hearing process contemplated in this Comprehensive Settlement Agreement by the withdrawal of a party, shall simultaneously go forward on parallel tracks so that the issues in this docket may be resolved at the earliest practicable time. The Parties agree that, if the Commission order on the Comprehensive Settlement Agreement could result in the termination of the CECP Settlement, Public Service immediately will request that the Commission stay the finality of the order pending resolution of the rehearing requests on this issue.

In the event that this Comprehensive Settlement Agreement is not approved, or is approved with conditions that are unacceptable to any Party who subsequently withdraws, the negotiations or discussions undertaken in conjunction with the agreement shall not be admissible into evidence in this or any other proceeding, except as may be necessary in any proceeding to enforce this Comprehensive Settlement Agreement.

Approval by the Commission of this Comprehensive Settlement Agreement shall constitute a determination that the agreement represents a just, equitable and

[21] Pursuant to Section 17(A) of the CECP Settlement, Public Service and the Parties that are signatories to the CECP Settlement have agreed to jointly request ARRR and, if necessary, a second ARRR of any Commission order that would result in the termination of the CECP Settlement.

reasonable resolution of all issues that were or could have been contested among the Parties in this proceeding. The Parties state that reaching agreement in this docket by means of a negotiated settlement is in the public interest and that the results of the compromises and settlements reflected by this Comprehensive Settlement Agreement are just, reasonable and in the public interest.

All Parties to this Comprehensive Settlement Agreement have had the opportunity to participate in the drafting of this agreement. There shall be no legal presumption that any specific Party was the drafter of this agreement.

This agreement may be executed in counterparts, all of which when taken together shall constitute the entire agreement with respect to the issues addressed by this agreement.

Dated this 3rd day of December, 2004.

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Settlement Agreement

This Settlement Agreement is executed this ___ day of _________, 2004, by and between Public Service Company of Colorado and the Concerned Environmental and Community Parties, as defined below.

Recitals

A. Public Service Company of Colorado has proposed to construct a new 750 MW coal-fired unit at the Comanche Station located near Pueblo, Colorado.

B. Concerned Environmental and Community Parties object to the environmental impacts associated with Comanche 3 and Public Service Company of Colorado's proposed 2003 Least-Cost Resource Plan filed with the Colorado Public Utilities Commission ("CPUC").

C. This Settlement Agreement is intended to address Concerned Environmental and Community Parties' objections regarding the pre-construction air permit for the new unit at Comanche 3 and the 2003 Least-Cost Resource Plan.

Agreement

1. Parties.

A. Public Service Company of Colorado ("PSCo") is a Colorado public utility and a wholly owned subsidiary of Xcel Energy Inc., a public utility holding company. PSCo does business in Colorado as "Xcel Energy."

B. Concerned Environmental and Community Parties ("CECP") consists of the following organizations and their Affiliated Organizations:

a. Western Resource Advocates;
b. Sierra Club;
c. Environmental Defense;
d. Environment Colorado;
e. Better Pueblo;
f. Diocese of Pueblo;
g. Southwest Energy Efficiency Project;
h. Colorado Renewable Energy Society; and
i. Smart Growth Advocates.

C. The term "Affiliated Organizations" means any organization under common management and control with any of the CECP parties or any successor to any CECP party.

D. The term "PSCo" means Public Service Company of Colorado or any of its successors or assigns.

2. Definitions.

A. "Comanche 3" shall be defined to mean a new coal-fired steam electric generating unit with a net summer dependable capacity of 750 MW, and a maximum gross heat input rate of approximately 7421 million Btu per hour as set forth in the preconstruction air permit application, and to be located at the existing Comanche Station near Pueblo, Colorado. PSCo shall amend the Clean Air Act Title V operating permit for Comanche Station to reflect the rated heat input of Comanche 3 in the same manner as the rated heat input is reflected for Comanche 1 & 2.

B. "Comanche 1" and "Comanche 2" shall be defined to mean the existing coal-fired steam electric generating units located at the Comanche Station near Pueblo, Colorado. PSCo owns and operates Comanche 1 and Comanche 2.

C. "2003 LCP" shall be defined to mean PSCo's 2003 proposed Least-Cost Resource Plan and to include any contingency plans for the 2003 Least-Cost Resource Plan pursuant to Rule 3614(b)(II) of the Colorado Electric Least-Cost Resource Planning Rules or any amendments to the 2003 Least-Cost Resource Plan pursuant to Rule 3615 of the Colorado Electric Least-Cost Resource Planning Rules.

D. "All-Source Solicitation" shall be defined to mean the All-Source solicitations under the 2003 LCP.

3. Emission limits for sulfur dioxide emissions.

A. PSCo shall amend its pre-construction permit application for Comanche 3 to propose one or more emission limits for sulfur dioxide ("SO_2") that are equivalent to Best Available Control Technology ("BACT") as defined in the Clean Air Act at 42 U.S.C. § 7479(3). PSCo shall design, install and operate a lime spray dryer sulfur dioxide removal system at Comanche 3 consistent with all SO_2 emission limits determined by the Colorado Department of Public Health and Environment ("Department") to be equivalent to BACT in accordance with the federal Clean Air Act at 42 U.S.C. § 7479(3). In no event shall the mass emission SO_2 limit determined by the Department to be equivalent to BACT for Comanche 3 be less stringent than 0.1lb./mmbtu heat input on a 30-day rolling average basis including emissions from shutdown and malfunction events. PSCo shall not seek an exemption for emissions during startup, shutdown or malfunction except for emissions during cold startups but such exemption shall be for no more than two hours after coal is first fed to the boiler.

B. PSCo shall comply with the emission limits set forth and contemplated by Section 3.A within 60 days after achieving the maximum production rate at which Comanche 3 will be operated, but no later than 180 days after initial startup.

C. PSCo shall install lime spray dryer SO_2 removal systems at Comanche 1 and 2 and meet a mass emissions SO_2 limit of 0.12 lb/mmbtu heat input on each unit as determined on a 30-day rolling average basis including emissions from shutdown and malfunction events. PSCo shall not seek an exemption for emissions during startup, shutdown or malfunction except for emissions during cold startups but such exemption shall be for no more than two hours after coal is first fed to the boiler. In addition, PSCo agrees that the combined average SO_2 emissions from both Comanche 1 and 2 taken together shall not exceed a 0.1 lb/mmbtu heat input emission limit on an annual rolling average basis (rolling on a daily basis) including emissions during startup, shutdown and malfunction events.

D. Within 60 days of the effective date of this Settlement Agreement, PSCo shall incorporate the emission limits set forth in this Section for Comanche 1, 2, and 3 into the pre-construction permit application filed for Comanche 3.

4. Emission limits for oxides of nitrogen.

A. PSCo shall amend its pre-construction permit application for Comanche 3 to propose one or more emission limits for oxides of nitrogen ("NO_x") that are equivalent to BACT as defined in the Clean Air Act at 42 U.S.C. § 7479(3). PSCo shall design, install and operate a selective catalytic reduction system for NO_x removal at Comanche 3 consistent with all NO_x emission limits determined by the Department to be equivalent to BACT in accordance with the federal Clean Air Act at 42 U.S.C. § 7479(3). In no event shall the NO_x emission limit determined by the Department to be equivalent to BACT for Comanche 3 be less stringent than 0.08 lb/mmbtu heat input on a 30-day rolling average basis, including shutdown and malfunction events. PSCo shall not seek an exemption for emissions during startup, shutdown or malfunction except for emissions during cold startups but such exemption shall be for no more than two hours when natural gas-fired igniters are in use, and for no more than four hours after coal is first fed to the boiler.

B. PSCo shall comply with the emission limits set forth and contemplated by Section 4.A within 60 days after achieving maximum production rate at which Comanche 3 will be operated, but no later than 180 days after initial startup.

C. PSCo shall install advanced low-NO_x emission control or reduction technologies on the existing Comanche 1 and 2 units and meet a NO_x

emission limit of 0.2 lb/mmbtu heat input at each unit as determined on a 30-day rolling average basis, including shutdown and malfunction events. In addition, PSCo agrees that the combined average NO_x emissions from both Comanche 1 and 2 taken together shall not exceed a 0.15 lb/mmbtu heat input limit on an annual rolling average basis (rolling on a daily basis), including shutdown and malfunction events. With respect to these limits, PSCo shall not seek an exemption for emissions during start up, shutdown or malfunction except for emissions during cold startups but such exemption shall be for no more than two hours when natural gas-fired igniters are in use, and for no more than four hours after coal is first fed to the boiler.

D. Within 60 days of the effective date of this Settlement Agreement, PSCo shall incorporate the emission limits set forth in this section for Comanche 1, 2 and 3 into the pre-construction permit application filed for Comanche 3.

5. Limits for particulate matter.

A. PSCo has submitted a pre-construction permit application for Comanche 3 that proposes emission limits for particulate matter ("PM") that PSCo represents is BACT as defined in the Clean Air Act at 42 U.S.C. § 7479(3). PSCo shall design, install and operate a fabric filter dust collection system for PM removal at Comanche 3 consistent with all PM emission limits determined by the Department to be BACT in accordance with the federal Clean Air Act at 42 U.S.C. §§ 7475(a)(4) and 7479(3). In no event shall the PM limits determined by the Department to be BACT for Comanche 3 be less stringent than those set forth below, and within 60 days of this Settlement Agreement PSCo shall amend its pre-construction permit application to incorporate such limits to the extent they are not currently in such application:

a. Filterable PM_{10} emissions shall be no greater than 0.0130 lb/mmbtu heat input;

b. Total PM_{10} emissions (including condensibles) shall be subject to enforceable emission limitations as determined by the Department;

c. Opacity shall be no more than 10 percent on a 6-minute average, excluding excess emissions during periods of startup, shutdown and malfunction if properly documented and reported consistent with 40 C.F.R. 60.7(c) and any other applicable requirements.

The emission limits set forth in this Section shall become enforceable under this Settlement Agreement in accordance with the terms of the final Comanche 3 preconstruction permit.

6. Installation and compliance schedule.

PSCo shall design and install all SO_2 and NO_x control equipment required to comply with the emissions limitations for Comanche 1 and 2 described in, and contemplated by, Sections 3 and 4 so that such control equipment is operational by December 31, 2008. PSCo shall meet the unit-specific emission limits for Comanche 1 and 2 no later than 180 days after initial startup of the SO_2 and NO_x control equipment for each unit, or by July 1, 2009, whichever is earlier. PSCo shall begin calculating compliance with the SO_2 and NO_x combined annual rolling average emission limits (rolling on a daily basis) for Comanche 1 and 2 no later than 180 days after initial startup of the SO_2 and NO_x control equipment for the last unit. PSCo shall incorporate the installation and compliance schedule for Comanche 1 and 2 set forth in this Section into the pre-construction permit application filed for Comanche 3.

Compliance with the SO_2, NO_x, and opacity limits set forth in, or contemplated by, this Settlement Agreement shall be determined at the Comanche Station by continuous SO_2, NO_x, and opacity monitors, and any other monitors or systems required by the Department or the U.S. Environmental Protection Agency ("EPA"), and PSCo shall install and operate all such monitoring systems in conformance with all applicable Department and EPA requirements and performance specifications.

7. Monitoring, testing and emission limits for mercury.

   A. PSCo shall comply with any applicable mercury emission limitations and requirements at Comanche 1, 2, and 3, including the requirement for case-by-case maximum achievable control technology emission limitations under the Clean Air Act at 42 U.S.C. § 7412(g)(2) for Comanche 3. PSCo shall also amend its permit application for Comanche 3 to request a mercury emission limit at Comanche 3 that is at least as stringent as the 20×10^{-6} lb/MWh mercury emission limit as proposed by EPA at 69 Fed. Reg. 4652 (January 30, 2004) for new coal-fired steam electric generating units burning sub-bituminous coal.

   B. Within one year after the date that the Comanche 3 pre-construction air permit is issued by the Department, PSCo shall install, properly maintain and operate a continuous mercury emissions monitoring system on Comanche 1 and 2 using Q-SEMS technology as described at 69 Fed. Reg. at 4694 (January 30, 2004), or such other technology as the Parties may agree. PSCo shall monitor mercury emissions from Comanche 1 and 2 beginning 18 months after the issuance of the Comanche 3 air permit and shall report the quality assured and quality controlled data to CECP and the Department on a calendar quarterly basis thereafter.

C. PSCo shall operate and maintain the mercury monitoring technology in accordance with EPA requirements and the manufacturer's specifications. In the event of any mercury monitoring technology malfunction, PSCo shall either repair or replace such monitoring technology. If the mercury monitoring technology identified in Section 7.B is unable to meet applicable performance requirements, despite PSCo's efforts to repair and replace such technology, PSCo agrees to install alternate mercury monitoring technology unless technologically or economically infeasible or to conduct annual stack testing if monitoring technology is technologically or economically infeasible.

D. Within 60 days after achieving the maximum production rate at which Comanche 3 will be operated, but in no event later than 180 days after initial startup of Comanche 3, PSCo shall install equipment necessary to use sorbent injection technology to control mercury at Comanche 3. On or before the SO_2 and NO_x controls installation deadline for Comanche 1 and 2 as provided in Section 6, PSCo shall install equipment necessary to use sorbent injection technology to control mercury at Comanche 1 and 2.

E. Within 60 days after achieving the maximum production rate at which Comanche 3 will be operated, but no later than 180 days after initial startup, PSCo shall test for a period of one year different mercury emission control methods or technologies on Comanche 1 and 2. Such methods or technologies shall be selected by PSCo in its sole discretion after consultation with CECP and may include methods or technologies other than sorbent injection. PSCo shall provide CECP with a report detailing the results of the tests, the conclusions arising from the tests and the bases for such conclusions. The report required under this paragraph shall be provided to CECP within 18 months after the commencement of the testing required by this paragraph. If PSCo claims information in the report contains trade secrets, any organization listed in Section 1 shall nevertheless be allowed to review such information after signing a reasonable confidentiality agreement that ensures that such trade secrets are protected.

F. No later than two years after the initial startup of Comanche 3, PSCo shall comply with a plant-wide mercury emission limit for the Comanche Station that maximizes cost-effective (as defined below) mercury reductions on a plant-wide basis. To implement this paragraph, PSCo shall propose a plant-wide emission limit to the Department in accordance with this paragraph after consultation with CECP. Unless otherwise agreed by the Parties, PSCo shall comply with an emission limit under this paragraph that represents the maximum cost-effective reduction of mercury at Comanche Station, achievable through the expenditure of no less than $2 million per year and no more than $5 million per year in the first year's operations and maintenance costs directly associated with mercury controls, excluding mercury monitoring costs and the operations and maintenance control costs for SO_2, NO_x, PM or any other pollutant regardless of whether such controls reduce mercury emissions but including the mercury control costs necessary to comply with the applicable mercury emission limitations set forth in Paragraph 7.A. If PSCo proposes to set an emission limit that will cost less than $5 million per year in the first year operations and maintenance costs to maximize the reduction of mercury, PSCo shall bear the burden of demonstrating to the Department that a more stringent emission limitation than that proposed by PSCo is not cost-effective based on a dollar per pound of mercury removed.

PSCo shall seek from the Department a determination under this paragraph that is reviewable by the Colorado Air Quality Control Commission in a proceeding in which CECP may be a party. The Parties recognize that the Department shall have the responsibility to set the emission limit in accordance with its procedures. PSCo agrees that CECP shall have full rights and discretion under law to participate in the Department's proceeding and in any subsequent review by the Colorado Air Quality Control Commission commenced in accordance with this paragraph.

G. Within 60 days after the effective date of this Settlement Agreement, PSCo shall amend its preconstruction air permit application for Comanche 3 to incorporate the requirements of Section 7.A that are applicable to Comanche 3 and to incorporate the requirement to install and operate the Q-SEMS technology under this Section.

8. Other air permit issues.

A. This Settlement Agreement is not a permit. Furthermore, PSCo shall comply with all applicable present and future federal, state and local laws, regulations and permitting requirements regardless of whether they are set forth in this Settlement Agreement. To the extent any conflict arises between any requirement in this Settlement Agreement and any other applicable present or future requirement described above, the most stringent requirement shall apply.

B. Notwithstanding any other provision of this Settlement Agreement, PSCo retains ownership of and all rights associated with any and all credits or emission allowances allocated to it under any law, rule, regulation, policy, or contract, whether such law, rule, regulation, policy or contract is currently in effect or becomes effective in the future.

C. In addition to other purposes, PSCo is installing the emission controls on Comanche 1 and 2 pursuant to this Settlement Agreement for the purpose of netting out of Prevention of Significant Deterioration ("PSD") review for SO_2 and NO_x for Comanche 3; as such controls are necessary and appropriate to ensure timely permitting of Comanche 3. PSCo agrees that such emission reductions necessary for netting shall become federally enforcable in the pre-construction permit and, pursuant to Section 16.F, the Clean Air Act Title V operating permit. All other emission reductions required by this Settlement Agreement shall become federally enforceable as otherwise provided under the Agreement.

D. In addition to the other emission limits, acid gas emissions (including sulfuric acid mist, hydrogen fluoride and hydrogen chloride) shall be subject to enforceable emissions limitations as determined by the Department.

E. Provided that PSCo's pre-construction air permit application, and the final permit, are consistent with Sections 3-8 of this Settlement Agreement, CECP agrees that it shall not submit any adverse formal comments or testimony on the permit application or proposed or final permit to the Department or EPA during the pre-construction permit review proceeding for Comanche 3 unless any provision in such permits is materially inconsistent with, or materially diminishes the stringency of, any requirement in this Settlement Agreement. Notwithstanding the above, if PSCo appeals any Comanche 3 permit term, CECP shall be allowed to intervene and participate as a party in the appeal proceeding regarding such term.

F. The Parties agree that they shall provide the Department with a copy of this Settlement Agreement as part of the pre-construction air quality permit proceeding for Comanche 3.

G. PSCo shall include in its pre-construction air permit application for Comanche 3 and the air permit for Comanche 1 and 2 a request for a condition that, at all times, including periods of startup, shutdown, and malfunction, PSCo shall, to the extent practicable, maintain and operate any emission control equipment required under this Settlement Agreement in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Department which may include, but is not limited to, monitoring results, observations, review of operating and maintenance procedures, and inspection of the source.

9. Additional environmental mitigation.

To mitigate the potential impacts to the Pueblo area of emissions from Comanche 3:

A. Within 3 months after issuance of the preconstruction air permit for Comanche 3, PSCo shall contribute $50,000 to the Department for implementation of a program to reduce mercury contamination in shredded car bodies provided to the Rocky Mountain Steel plant in Pueblo. PSCo shall make an additional contribution of $50,000 to the Department for the same program within one year after its initial contribution.

B. Within 6 months after the issuance of the Comanche 3 air permit, PSCo shall contribute a total of $250,000 to Pueblo School Districts No. 60 and 70 to reduce air pollution from existing diesel school buses in the Pueblo area, provided that the school districts agree to accept the donation, maintain the funds in a separate account, and expend the funds to achieve the maximum reduction of air pollution from existing diesel school buses at the least cost. School bus emissions may be reduced through any one or more of the following: retrofitting existing buses with EPA verified pollution control devices such as particulate filters and diesel oxidation catalysts, replacing existing buses with new buses that are consistent with EPA's Clean School Bus USA program, and using ultra-low sulfur diesel fuel or other cleaner fuels.

10. Sustainable development in the Pueblo region.

A. PSCo and CECP shall jointly sponsor, in cooperation with other appropriate stakeholders, a series of public forums addressing sustainable development in the Pueblo area. The parties shall invite other stakeholders from the Pueblo community (including, but not limited to, the Pueblo Economic Development Corporation, Better Pueblo, industry, government and citizens of Pueblo and surrounding areas) to participate in the public forums.

B. The sustainable development forums shall consider and examine the following issues generally applicable to the Pueblo community:

a. Long-term economic development;

b. Energy and technology issues;

c. Environmental concerns;

d. Environmental justice;

e. Public safety;

f. Water and water rights; and

g. Other issues that the forums may identify.

C. In conjunction with these forums, PSCo shall participate in the Pueblo Sustainable Development Program.

D. PSCo and CECP shall make best efforts to begin these forums within three months and shall begin these forums no later than four months after execution of this Settlement Agreement. Both parties are jointly responsible for the logistics and arrangement of these meetings. PSCo recognizes that CECP shall not have any financial responsibility under this Section. The Parties shall make best efforts to include other stakeholders in the process by the date of commencement of the forums.

E. Among other things, the forums created hereunder shall:

a. consider the preparation of a study to identify appropriate analytical tools to help the community evaluate the impact of economic development proposals; and

b. identify opportunities to seek funding from third party charitable foundations or other sources for technical assistance on sustainable development issues. PSCo shall provide reasonable assistance, appropriate involvement and support in seeking such funding.

F. PSCo's obligations under this Section shall cease upon termination of the Settlement Agreement unless otherwise agreed to by the Parties.

11. Emissions data.

A. Beginning within one year after the date that the Comanche 3 pre-construction air permit is issued by the Department, PSCo shall make available on the Xcel Energy website electronic links to the emissions reports and emissions data related to the Comanche plant that are submitted to EPA and the Department. Such reports and data shall be made available only after they have been subject to quality assurance and quality control measures.

B. PSCo shall use its best efforts to make the emissions data described in this Section available on the Xcel Energy website within 30 days after submission to EPA

C. PSCo shall provide each organization listed under Section 1 an opportunity to review and comment on the format of the emissions data posted on its website under this Section.

12. Carbon Dioxide Proxy Cost.

A. PSCo shall include a carbon dioxide ("CO_2") proxy cost in its analysis and evaluation of the cost of resource bids submitted in response to the All-Source Solicitation. PSCo shall issue the Request for Proposals ("RFP") for the All-Source Solicitation consistent with this Section.

B. The CO_2 proxy cost shall:

a. be set at $9 per ton[1] of CO_2;

b. be first applied to resources beginning in the year 2010 in the bid evaluation process; and

c. escalate at a rate of 2.5% per year starting in 2011 and continuing over the planning life of the resource.

C. The CO_2 proxy cost shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation process. In evaluating bids during the initial economic screening, PSCo shall reflect the costs associated with the CO_2 proxy cost as a $/MWh variable operating cost. In evaluating the bids dynamically, PSCo shall model the costs associated with the CO_2 proxy cost as a $/MWh variable operating cost affecting resource dispatch. In the dynamic portfolio optimization modeling, the CO_2 proxy cost shall be applied to both existing and new resources. For any CO_2 emitting resource, the variable $/MWh CO_2 cost of a resource shall be calculated using the following formula:

$$CO_2\ cost_t = [E_t * HR_t * C_t]/(2*10^6)$$

where: E_t = CO_2 emission rate of the resource in lb/mmbtu heat input at time t;
HR_t = heat rate of the resource in btu/kWh at time t; and
C_t = CO_2 proxy cost in $/ton at time t.

13. Innovative technologies.

A. PSCo and CECP shall work jointly on innovative technologies, practices and measures to examine cost-effective programs and strategies to reduce greenhouse gas emissions, including but not limited to the innovative technology program described herein. The programs and strategies may also include terrestrial or geological carbon sequestration and small-scale and community-owned renewable energy projects.

B. PSCo shall work with CECP to seek passage of legislation in the 2005 legislative session of the Colorado General Assembly to create the framework for an innovative technology program in the state of Colorado. The innovative technology program shall promote the use of innovative technologies on a demonstration scale to generate or conserve electricity for Colorado electricity consumers. The program shall promote the use of technologies designed to allow more efficient production or consumption of electricity with fewer emissions of greenhouse gases on a plant or system-wide basis. The program shall ensure that utilities implementing a demonstration project under its terms shall have the right to full and timely recovery of all costs associated with any subject demonstration project.

C. If the Colorado General Assembly enacts innovative technology program legislation consistent with Section 13.B in the 2005 legislative session, PSCo shall, within 12 months after the date that the Comanche 3 pre-construction air permit is issued by the Department, propose an innovative technology demonstration project under the terms of that program. Such innovative technology demonstration project shall be selected by PSCo in its sole discretion after consultation with CECP. In proposing the project under this paragraph, PSCo may consider technologies that include, but are not limited to, compressed air storage/wind combination, renewably generated hydrogen for fuel cells, or integrated gasification combined cycle power plants fueled with western coal.

D. The Parties shall consider siting the innovative technology measures, practices or demonstration project in the Pueblo area.

E. The goal of the innovative technology demonstration project under this Section shall be to reduce in a cost-effective manner CO_2 emissions by a cumulative total of 1.67 million tons as measured over the years 2006-2013. Progress toward the cumulative 1.67 million ton reduction goal shall be measured through expansion or production cost model projections associated with the innovative technology demonstration project. PSCo shall make its best efforts to achieve this goal. The Parties recognize that the performance of innovative technology demonstration projects is uncertain, and cost or technology performance problems may prevent achievement of the goal.

F. Notwithstanding the foregoing, PSCo shall not be required to achieve the CO_2 mitigation goal set forth above or implement the innovative technology practices, measures or demonstration project above unless it receives adequate assurance of timely cost recovery and all required approvals for the practices, measures or projects.

G. The Parties agree to work in good faith to obtain additional funding for the innovative technology demonstration project from the United States Department of Energy and obtain authority to implement the project and recover its costs from the Colorado General Assembly and the Public Utilities Commission, as appropriate.

14. Energy Efficiency.

A. PSCo shall use its best efforts to acquire, on average, 40 MW of demand reduction and 100 GWh of energy savings per year over the period beginning January 1, 2006 and ending December 31, 2013, so that by January 1, 2014, the company will have achieved 320 MW of total demand reduction and 800 GWh of annual energy savings. Notwithstanding the foregoing sentence, PSCo's actual annual demand reductions and energy savings during this period may vary from these averages. PSCo shall expend $196 million (in 2005 dollars) to meet such demand reduction and energy savings unless these demand reduction and energy savings are achieved with a lower level of expenditure. The demand-side management ("DSM") levels set forth in this Section shall include the demand reduction and energy savings achieved by PSCo through the All-Source Solicitation. All DSM programs implemented outside of the All-Source solicitation shall be required to pass the Total Resource Cost test. PSCo shall strive to implement a set of DSM programs that give all classes of customers an opportunity to participate.

B. PSCo shall conduct a market study to determine, generally, levels of efficiency available for various customer classes and the costs associated with such measures, and whether such levels of DSM are cost-effective and prudent in Colorado. In addition, PSCo shall conduct program-specific market and load research, and ongoing DSM program measurement and evaluation. The cost of the market study and these other research and evaluation activities is included in the total amount of DSM expenditures in Section 14.A but shall not exceed $4 million. PSCo agrees to involve other stakeholders in the design of the market study and the review of the contractor summary results. PSCo shall complete the study as expeditiously as practicable, but no later than March 31, 2006.

C. PSCo shall be entitled to fully recover its expenses and investments associated with the acquisition of the DSM programs under Section 14.A and the cost of the market study and other activities described in Section 14.B through PSCo's Demand-Side Management Cost Adjustment Clause or other mechanisms.

D. Within three months of completing the market study described in Section 14.B but no later than July 1, 2006, PSCo shall request that the CPUC open a docket to consider issues related to DSM, including the appropriate test used to judge the cost effectiveness of DSM projects, the viability of additional DSM in Colorado's economy, best DSM practices and other issues related to increased investment in energy efficiency measures by PSCo. In this docket, the Parties shall advocate a DSM policy that (1) uses the Total Resource Cost test to determine the cost-effectiveness of DSM programs; (2) provides for recovery of all costs of approved DSM programs, including, but not limited to, administrative, internal and external labor, and promotion costs; and (3) creates an incentive mechanism that promotes PSCo's investments in additional energy efficiency beyond the levels set forth in Section 14.A. The incentive program described in this paragraph may include compensation to PSCo for its loss of energy sales as a result of the DSM program.

E. PSCo shall report to the CPUC and other parties on DSM expenditures, energy savings, and peak demand reductions achieved by the programs each year.

F. PSCo shall establish and maintain a DSM working group that shall meet at least twice a year. The DSM working group shall be open to all interested parties and shall provide input to PSCo in DSM program design, analysis and other issues relevant to helping PSCo meet or exceed the minimum energy savings and peak demand reduction levels.

15. Renewable energy.

A. PSCo shall accelerate and complete those components of the wind ancillary service cost study[2] that are necessary to obtain projections of ancillary service costs for nameplate wind capacity penetration levels of 15% of PSCo's system peak demand. These necessary components of the study shall be completed in time to evaluate wind resource bids submitted in the All-Source Solicitation. For purposes of the study, the 15% wind penetration level shall be based on PSCo's 2007 peak demand forecast or the Company's best available peak demand forecast for 2007 at the commencement of the study. The study shall include consideration of the operational flexibility of its Cabin Creek pumped-storage generation facility. PSCo has solicited participation of stakeholders on a technical review committee with the intent of incorporating their specific interest and knowledge base into the study. The invitation was sent to industry experts, intervenors, PUC staff and PSCo personnel. PSCo shall produce a report detailing the results of the study. If PSCo claims information in the report is confidential, any member of the technical review committee or any organization listed in Section 1 shall nevertheless be allowed to review such information after signing a reasonable confidentiality agreement that ensures that commercially sensitive or trade secret information is protected.

B. As previously ordered by the CPUC in the 2003 LCP Renewable Energy RFP docket, PSCo shall use an ancillary service cost of \$2.50/MWh (escalating at the same rate as gas prices) for wind bids up to 500 MW that are acquired in the renewable energy RFP. PSCo shall use the results of the study in Section 15.A to evaluate all wind bids in the All-Source Solicitation.

C. PSCo shall accept wind bids up to a 15% penetration level, so long as the wind bids are part of PSCo's Least Cost Resource Portfolio. For this purpose, the 15% wind penetration level shall be based on PSCo's peak demand forecast used to determine resource need and acquisition at the time of the bid evaluations and shall be calculated based on the year in which the wind resource would be projected to come on-line. If PSCo selects wind generation resources in response to the Renewable Energy RFP and All-Source Solicitation that increase nameplate wind generation on its system above 720 MW, PSCo agrees to undertake an additional wind ancillary service cost study to obtain projections of ancillary service costs at a 20% penetration level. This additional 20% wind penetration study shall be used to inform subsequent resource solicitations. PSCo shall not be required to "hold" bids for further evaluation pending the outcome of the 20% wind penetration study, but nothing in this Settlement Agreement prevents PSCo from doing so.

D. PSCo shall use a capacity value of wind generation resources equal to 10% of nameplate capacity in evaluating bids submitted in response to the All-Source Solicitation. PSCo shall perform a study of effective load carrying capability on its system as a means of determining the capacity value of wind generation resources. The study shall include consideration of the uncertainty or variability of hourly wind generation patterns from year to year and the combined effects of diverse wind farm locations. PSCo agrees to (1) file, by November 1, 2006, the study results with the CPUC; (2) advocate that the reliability contribution or capacity value of wind generation resources should be based on a method that incorporates consideration of reliability contribution in all hours in the year; and (3) include recommendations for ascribing capacity value to existing and new wind generation resources. PSCo shall solicit participation of industry experts, intervenors, CPUC Staff and PSCo personnel on a technical review committee with the intent of incorporating their specific interest and knowledge base into the study. PSCo shall produce a report detailing the results of the study. If PSCo claims the information in such report is confidential, any member of the technical review committee or any organization listed in Section 1 shall nevertheless be allowed to review such information after signing a reasonable confidentiality agreement that ensures that commercially sensitive or trade secret information is protected.

E. PSCo shall include a renewable energy credit ("REC") value of $8.75/MWh in its analysis and evaluation of the cost of renewable resource bids submitted in response to the All-Source Solicitation. To qualify for the REC value in the bid evaluation, a renewable energy bid must meet the definition of "Eligible Renewable Energy Resource" under the 2004 Colorado Ballot Initiative Amendment 37 as may be updated by the Colorado Legislature by the time that bids are due in the All-Source Solicitation. The REC value shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation process. PSCo shall apply the REC value to renewable resource bids in the All-Source Solicitation, for all operating years of the renewable energy project beginning in 2006. CECP acknowledges that nothing in this provision shall prohibit PSCo from negotiating with individual bidders exceptions to the Model Nondispatchable Power Purchase Agreement allowing such bidders to retain some or all the RECs associated with a renewable energy bid, but such bids shall not include the $8.75 REC value in the bid evaluations in the All-Source Solicitation for any RECs so retained.

16. Commitments of the Parties.

A. As long as PSCo remains in material compliance with this Settlement Agreement, the CECP organizations agree not to make any adverse formal comments before the Department or EPA or to bring a lawsuit asserting that any projects or construction undertaken at Comanche Station prior to the effective date of this Settlement Agreement in any way violated the requirements of section 165(a) of the federal Clean Air Act, 42 U.S.C. § 7475(a), or the related requirements of the federally enforceable applicable implementation plan. The CECP organizations also agree not to initiate, fund or participate in any such comments or lawsuit by any other entity. If for any reason PSCo does not materially comply with this Settlement Agreement, or otherwise does not satisfy its obligations, or if the Department does not issue a proposed or final Clean Air Act pre-construction permit and/or Clean Air Act Title V operating permit that is consistent with the terms of this Settlement Agreement in all material respects, the CECP organizations are released from their agreement not to comment or sue described above in this paragraph. PSCo agrees that in any ensuing proceeding PSCo shall not use or count the period of time in which CECP's agreement not to challenge or sue was in effect as support for any otherwise available defense of statute of limitations, laches, delay or other defense based on failure to timely comment on or prosecute any such violations of the federal Clean Air Act or the federally enforceable applicable implementation plan.

B. The Parties agree that this Settlement Agreement is a fair and reasonable resolution of the issues related to the construction and operation of Comanche 3 as addressed in this Settlement Agreement. Subject to Section 8.A, the reservation of rights in Section 17.J, and the dispute resolution and repudiation provisions in Sections 17.F. and 17.G, the CECP organizations agree they shall not initiate, fund or participate in any formal administrative or legal action to oppose or knowingly impede any of the following administrative or regulatory approvals necessary for PSCo to construct or operate Comanche 3 in accordance with this Settlement Agreement:

a. The issuance of a certificate of public convenience and necessity ("CPCN") for Comanche 3 in the 2003 LCP proceeding;

b. The granting of PSCo's application to waive Rule 3610(b) of the CPUC Least Cost Planning Rules for Comanche 3 in the 2003 LCP proceeding; and

c. The issuance of the pre-construction air permit by the Department or the authorized permitting authority required for the construction of Comanche 3 and the Clean Air Act Title V operating permit for the Comanche Station necessary to implement this Settlement Agreement. Notwithstanding the above, the CECP organizations reserve their right to comment on and challenge any provision in such permits that is materially inconsistent with, or materially diminishes the stringency of any requirement in, this Settlement Agreement.

C. CECP agrees that if any of the CECP organizations initiate, fund or participate in any administrative or legal action to oppose or knowingly impede the permitting or approval of any activities necessary to complete the construction and initial startup of Comanche 3, including associated facilities such as the CPCN and right-of-way for the transmission, PSCo may take action to terminate this Settlement Agreement in accordance with the pre-enforcement and repudiation procedures in Section 17. Before taking any such action, any CECP organization may notify PSCo of any grievance it has with respect to any proposed permit or approval and PSCo shall meet with the CECP organization and use its best efforts to resolve timely such grievance. Upon termination under this paragraph, PSCo shall be relieved of any obligations under this Settlement Agreement, including any obligation to install emission controls under Sections 3-7, except as provided below. CECP's obligations under Sections 16.A and B shall survive termination under this paragraph. If PSCo's rights under this paragraph have been triggered after the pre-construction air permit for Comanche 3 is final and effective, PSCo's obligation to achieve and maintain compliance with the NO_x and SO_2 emission limits in this Settlement Agreement applicable to Comanche 1 and 2 shall survive termination.

D. In addition to the foregoing, the organizations listed under Section 1 that are Parties to the 2003 LCP/CPCN proceeding before the PUC agree not to oppose the regulatory plan submitted by PSCo in conjunction with the 2003 LCP/CPCN proceeding as such plan may be modified by PSCo so long as such regulatory plan is not inconsistent with and does not interfere with the requirements of this Settlement Agreement, and to support PSCo's recovery of the costs of all environmental components of this Settlement Agreement, including, but not limited to, the costs of any emission control equipment for the Comanche Station required hereunder. The organizations listed under Section 1 that are Parties to the 2003 LCP/CPCN shall not be bound to intervene in any future proceedings before the CPUC. The provisions of this paragraph do not apply to any CECP organization that is not a party to the PUC's 2003 LCP/CPCN proceeding.

E. Through a process established by mutual agreement of the parties, PSCo shall consult with CECP at least quarterly after execution of the Settlement Agreement to discuss the material issues associated with the implementation of the Settlement Agreement and other issues identified by mutual agreement. PSCo shall use best efforts to provide information as set forth in this paragraph, and its failure to provide information pursuant to this paragraph shall not be considered a breach of this Settlement Agreement. PSCo's obligation under this paragraph shall cease upon termination of the Settlement Agreement unless otherwise agreed by the Parties.

F. No later than 60 days after the last date for achieving the emission limits in this Settlement Agreement for Comanche Station, except for the mercury emission limit, PSCo shall file with the Department a proposed amendment to the Comanche Station Clean Air Act Title V operating permit to incorporate into the Title V permit such emission limits and all related applicable requirements set forth in this Settlement Agreement. If, however, the Comanche Station Title V permit will expire within 24 months of the last date described above, PSCo may advance or delay filing the application to amend the Title V permit until PSCo files its application to renew the Title V permit. PSCo agrees to include in any Title V permit for Comanche Station requirements no less stringent than those set forth in, or contemplated by, Sections 3-9 of this Settlement Agreement, which obligation shall survive termination of this Settlement Agreement under Section 20.

17. Enforceability and Reservation of Rights.

A. PSCo shall seek CPUC approval for the commitments in sections 3, 4, 5, 6, 7, 8, 12, 14, and 15 of this Settlement Agreement as part of the Commission order on the 2003 LCP. If CPUC action on such commitments is not approved and ordered in full, if a CPUC order significantly impedes implementation of any commitments under this Settlement Agreement, or if the CPUC order approving such commitments is reversed on judicial appeal in any significant respect, the Parties' obligations under this Settlement Agreement are terminated. If the Commission order on the 2003 LCP does not approve such commitments or if the Commission order on the 2003 LCP significantly impedes implementation of any commitments under this Settlement Agreement, PSCo and any party to the 2003 LCP proceeding listed under Section 1 that wish to seek rehearing, reargument or reconsideration agree to jointly request rehearing, reargument or reconsideration of the Commission order and, if necessary, request second rehearing, reargument or reconsideration. If PSCo reaches agreement with other parties to the 2003 LCP proceeding that significantly impedes implementation of any commitment under this Settlement Agreement, the Parties' obligations under this Settlement Agreement are terminated. PSCo agrees that if this Settlement Agreement is terminated under the provisions of this paragraph, PSCo shall not use or count the period of time in which CECP's agreement not to challenge or sue under Section 16.A was in effect as support for any otherwise available defense of statute of limitations, laches, delay or other defense based on failure to timely prosecute any such violations of the federal Clean Air Act or the federally enforceable applicable implementation plan.

B. Each organization listed under Section 1 shall have the full rights under the law afforded persons or corporations to enforce CPUC orders including the rights and powers under C.R.S. 40-7-101, et seq.

C. If PSCo fails to make amendments to its preconstruction air quality permit application for Comanche 3 or to propose emission limitations for Comanche 1 and 2 as required by this Settlement Agreement, or if either the Department's final federally enforceable Clean Air Act preconstruction permit or the Clean Air Act Title V operating permit for the Comanche Station is not materially consistent with the terms of this Settlement Agreement, or upon expiration of the pre-construction air permit for Comanche 3 before construction commenced, all of the Parties' obligations under this Settlement Agreement are terminated including but not limited to CECP's agreement not to comment, challenge or sue for alleged violations of the Clean Air Act under Section 16.A. In the event of termination under this paragraph, PSCo shall not oppose CECP's rights to challenge any pre-construction air quality or Clean Air Act Title V operating permit related to Comanche 3 or the Comanche Station solely as a result of CECP's failure to participate in the pre-construction air permitting administrative process.

D. CECP's Remedies for Breach. In consideration of PSCo's commitments under this Settlement Agreement, CECP and its Affiliated Organizations have agreed to forebear the exercise of specific procedural and substantive rights as set forth in Section 16 of the Settlement Agreement. In the event PSCo fails to perform any material obligation or commitment under Sections 3-11 of this Settlement Agreement, each organization listed under Section 1 or any Affiliated Organization shall, after exhausting the pre-enforcement procedures of Section 17.F, have the full discretion and rights to seek judicial or administrative relief to compel performance of such obligations pursuant to the terms hereof. PSCo hereby stipulates to subject matter jurisdiction under Colorado law, and to any such organization's standing to enforce specific performance of Sections 3-11 of this Settlement Agreement. In the event PSCo fails to perform any material commitments under Sections 3-11 of the Settlement Agreement, each of the organizations listed under Section 1 shall also have the option of exercising any rights that CECP has agreed to forego if this Settlement Agreement is fully performed.

E. PSCo's Remedies for Breach. In the event there is an alleged breach of Section 16 of the Settlement Agreement, PSCo, after exhausting the pre-enforcement and repudiation procedures of Section 17.E and 17.F, may bring suit against the particular organization listed under Section 1 that is alleged to be in violation. To the extent any alleged breach results in PSCo incurring additional costs or delay in the permitting or construction anticipated under this Settlement Agreement, PSCo may seek injunctive relief against the allegedly breaching organization. As provided in Section 17.H, each organization listed under Section 1 is a distinct and separate entity and the actions of one organization listed under Section 1 shall not be imputed to another. If injunctive relief for breach of this Settlement Agreement is granted against any of the organizations listed under Section 1 or a reviewing court declares any organization listed under Section 1 is in breach of this Settlement Agreement, PSCo shall not be obligated to undertake any action required under this Settlement Agreement including but not limited to the installation of emission control equipment on Comanche 1 and 2, provided that PSCo has complied with the material requirements under this Settlement Agreement prior to the alleged breach by the CECP organization.

F. Pre-enforcement Procedures. Before pursuing judicial relief to compel performance of obligations set forth in this Settlement Agreement, or before exercising any right to terminate this Settlement Agreement, CECP and PSCo shall first invoke the following notice and alternate dispute resolution procedures:

a. Notice. The affected Party shall provide written notice of alleged material breach to all parties to this Settlement Agreement. Such notice shall include a reasonable description of the facts and circumstances surrounding the alleged material breach, the term(s) of the Settlement Agreement at issue, and the measure(s) sought to correct any breach.

b. Informal Dispute Resolution. Within five business days of receipt of notice of alleged breach, the Parties shall meet and confer in person or by conference call at a mutually convenient time and place in an effort to resolve the alleged breach. Discussions to resolve the dispute among the parties shall continue for no less than 15 business days from the time notice of alleged breach is received and the affected party shall not institute or pursue an action in either state or federal court during this period. The bar against instituting or pursuing judicial enforcement of the obligations in this Settlement Agreement may be extended by mutual agreement of the Parties beyond the minimum period required for notice and informal dispute resolution.

c. Notice of Intent to Sue. Should the Parties be unable to resolve their disagreements within 15 business days from the time notice of alleged breach is received or the mutually agreed enlarged time for informal dispute resolution, the affected Party shall have the right, upon providing five business days notice of intention to seek judicial relief to all Parties, to seek judicial enforcement of the terms of this Settlement Agreement.

d. The requirements in this Section shall survive after termination of this Settlement Agreement to the extent any party seeks to enforce any obligation that survives after termination.

G. Repudiation by CECP. If any organization listed under Section 1 or any Affiliated Organization allegedly acts in breach of the commitments made in this Settlement Agreement, the organization listed under Section 1 or Affiliated Organization whose name has been invoked may repudiate such action either by letter (or other means mutually acceptable to the organization or Affiliated Organization and PSCo) within 15 business days of being informed of the alleged breach by PSCo pursuant to Section 17.E. Such letter or other mutually acceptable means shall constitute full and complete performance of the duties of any such organization or Affiliated Organization arising from the Settlement Agreement, and PSCo shall have no right to terminate or otherwise avoid its obligations under this Settlement Agreement. This provision shall survive termination of this Settlement Agreement.

H. The Parties agree that in no instance shall any Party or individual be responsible or liable for monetary damages, attorneys fees and/or costs incurred as a result of any alleged breach or breach of this Settlement Agreement. The parties acknowledge and agree that damages are not available as a remedy in the event the obligations of this Settlement Agreement are breached. The parties agree that damages would not be an adequate remedy for noncompliance with this Settlement Agreement, and that no adequate remedy at law exists for noncompliance with the terms of this Settlement Agreement. Accordingly, the parties expressly acknowledge that an award of equitable relief would be an appropriate remedy for a breach of the obligations under this Settlement Agreement, provided the reviewing court has followed standard procedures in issuing injunctive relief.

I. This Settlement Agreement does not create any legal relationship between or among the organizations listed in Section 1. Western Resource Advocates, Sierra Club, Environmental Defense, Environment Colorado, Better Pueblo, Diocese of Pueblo, Southwest Energy Efficiency Project, Colorado Renewable Energy Society, and Smart Growth Advocates are each separate and distinct organizations, and the actions of one organization shall not be imputed to another. The use of the term "Concerned Environmental and Community Parties" or "CECP" in this Settlement Agreement is intended merely for convenience and does not in any manner imply that one organization shall be held accountable or liable for the actions of another. Thus, each party is responsible only for its own actions and this Settlement Agreement is not intended to and does not in any manner create rights, duties, liabilities or legal consequences for the individual and separate entities Western Resource Advocates, Sierra Club, Environmental Defense, Environment Colorado, Better Pueblo, Diocese of Pueblo, Southwest Energy Efficiency Project, Colorado Renewable Energy Society, and Smart Growth Advocates arising out of the actions of any CECP or non-CECP organization, whether or not that organization is a party to this Settlement Agreement. No joint venture, agency, partnership or other fiduciary relationship shall be deemed to exist or arise between or among the parties or CECP groups as a result of this Settlement Agreement.

J. Further Reservation of Rights

a. Without in any way limiting CECP's commitments under Sections 16.A and 16.B, CECP reserves all rights not expressly waived in this Settlement Agreement, including but not limited to all rights:

- to seek administrative or judicial relief to address any violation of law by any private or governmental entity or any person;

- to challenge or enforce any federal, state or local statutory or regulatory or permit requirements, including any pre-construction permit application not required or necessary to complete the construction of Comanche 3 and associated facilities;

- to enforce any federal, state or local statutory or regulatory or permit requirements related to the operation of the Comanche Station after the effective date of and not otherwise addressed by this Settlement Agreement;

- to advocate any position in any future CPUC proceeding or forum and to promote clean energy and clean air throughout Colorado in any administrative, legislative or public forum;

- to challenge in every respect and in any proceeding or forum any proposal related to any new or expanded coal-fired power plant (except for Comanche 3 as set forth in this Settlement Agreement) including any proposals for any new power generation and associated facilities under the All-Source Solicitation and to obtain through all available means any information about such proposals for new power generation and associated facilities; and

- to comment publicly (positively or negatively) on any and all matters related to PSCo or any of its agents, subsidiaries, assigns or affiliated companies.

b. This Settlement Agreement constitutes a compromise and settlement of several contested issues. The commitments of PSCo hereunder are contingent upon the issuance of a CPCN for Comanche 3, the pre-construction air quality permit, the Clean Air Act Title V operating permit for Comanche 3, any other permits and approvals required for associated transmission and other facilities, any permits and approvals required to install pollution control equipment for Comanche 1 and 2 and assurance of adequate cost recovery. If PSCo withdraws the pre-construction air quality permit application for Comanche 3 for any reason (including third-party objections to the permit), or if PSCo does not diligently pursue a pre-construction air permit for Comanche 3 and such lack of diligence results in a delay in the issuance of the permit of more than 36 months from the effective date of this Settlement Agreement, or if the requisite approvals for the construction of Comanche 3 are not obtained, CECP's obligations under this Settlement Agreement including CECP's agreement under Section 16.A not to challenge or sue alleged Clean Air Act violations shall be terminated and PSCo shall have no obligation to undertake any of the improvements or actions set forth in this Settlement Agreement except that PSCo shall not be relieved of any obligation to comply with any order of the CPUC or any applicable legal requirements. PSCo's withdrawal of its pre-construction review permit application for Comanche 3 and/or a decision not to construct Comanche 3 shall not be considered a breach of this Settlement Agreement. PSCo agrees and acknowledges that in the event of termination under this paragraph PSCo shall not use or count the period of time in which CECP's agreement not to challenge or sue was in effect as support for any otherwise available defense of statute of limitations, laches, delay or other defense based on failure to timely prosecute any violations of the federal Clean Air Act or the federally enforceable applicable implementation plan at the Comanche Station.

Further, except as necessary to enforce any terms of this Settlement Agreement, PSCo's or CECP's willingness to compromise its positions on many of the issues addressed in this Settlement Agreement, including but not limited to the CO_2 proxy cost, shall not be used by any Party against PSCo or any of the organizations listed under Section 1 at proceedings at the CPUC or in any other forum and the Settlement Agreement shall not be construed as an admission against interest and shall be precluded as evidence pursuant to Rule 408 of the Federal Rules of Evidence.

18. Force Majeure

Neither Party shall be deemed to have breached this agreement or trigger a right to terminate this Settlement Agreement for any delay or default in performing hereunder if such delay or default is caused by conditions beyond its control including, but not limited to Acts of God, Government restrictions, wars, insurrections and/or any other cause beyond the reasonable control of the Party whose performance is affected.

19. Notice

Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Settlement Agreement, they shall be made in writing and addressed as follows:

As to PSCo:

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Xcel Energy
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Olon Plunk
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As to Sierra Club:

Sierra Club Coordinating Attorney
Sierra Club Environmental Law Program
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As to Better Pueblo:

Ross Vincent, Chair
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chair@betterpueblo.org

As to Diocese of Pueblo:

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Director, Office for Social Justice
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Ph: 719-544-9861, ext 112
Fax: 719-544-5202
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As to Smart Growth Advocates:

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719-565-0597
vmassam@comcast.net

As to Southwest Energy Efficiency Project (SWEEP):

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As to Environment Colorado:

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As to Colorado Renewable Energy Society:

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Fax: 303-526-0704
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As to Environmental Defense:

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As to Western Resource Advocates:

Energy Program Director
2260 Baseline Road, Suite 200
Boulder, CO 80302
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Fax: 303-786-8054
jnielsen@westernresources.org

All notifications, communications or submissions made pursuant to this Settlement Agreement shall be sent in electronic (pdf) format unless the size or other characteristics of the materials requires the submission of a hard copy. If hard copies are submitted, they shall be submitted by: (a) overnight mail or delivery service; or (b) certified or registered mail, return receipt requested. All notifications, communications and transmissions (a) sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked, or (b) sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service. All notifications, communications, and submissions made by electronic means shall be deemed submitted on the date that the transmitting Party receives written acknowledgment of receipt of such transmission. Any Party may change either the notice recipient or the address for providing notices to it by serving the other Parties with a notice setting forth such new notice recipient or address. Nothing herein is intended to limit informal communication between the Parties as contemplated by this Settlement Agreement.

20. Termination.

Unless terminated by mutual written agreement of the parties, PSCo shall notify CECP in writing at such time that it has complied with all of the requirements in this Settlement Agreement, and has obtained all Clean Air Act Title V operating permits and all federally enforceable emission limits that reflect all applicable requirements for the Comanche Station (including the plant wide emission limitation for mercury under section 7). This Settlement Agreement shall terminate and no longer be binding upon any party unless within 30 days of PSCo's notification, CECP subjects this issue to the dispute resolution procedures set forth in Section 17.F. PSCo shall provide any materially relevant information requested by CECP to assist CECP in evaluating PSCo's compliance determination described above.

Termination of this Settlement Agreement under this Section shall not relieve PSCo of any obligation to comply with any order of the CPUC or any applicable statutory, regulatory or permit requirements, including the emission limitations provided for by this Settlement Agreement for the Comanche Station; provided, however, that CECP's covenant not to sue in Section 16.A, and PSCo's obligation to ensure that all future permits for Comanche Station contain provisions that are at least as stringent as those in this Settlement Agreement, shall survive termination.

21. Amendment.

This Settlement Agreement only may be amended in writing by mutual agreement of the Parties.

22. Choice of Law.

This Settlement Agreement shall be construed and governed by the laws of the state of Colorado, without regard to the principles of conflicts of law.

23. Effective Date

This Settlement Agreement becomes effective on the date of the signature of the last party.

24. Additional Provisions.

25. Each of the signatories to this Settlement Agreement affirm that he or she is authorized to enter into the terms and conditions of this Settlement Agreement. Each party hereto may validly execute this document by facsimile signature or in

counterparts each of which shall constitute an original and all of which shall constitute one and the same Agreement.

Endnotes

1. The term "ton" means 2000 English pounds.

2. The wind ancillary service cost study was previously ordered by the CPUC in the 2003 LCP Renewable Energy RFP docket (Docket No. 04A-325E) and is required to be completed by April 1, 2006. The parties recognize that some of the study components not required under Section 13.A, but required by the CPUC's Renewable Energy RFP order, cannot be completed in time to inform the All-Source Solicitation. Those components shall be included in the April 1, 2006 study results.

AGREED & APPROVED BY:

Better Pueblo

____

Ross Vincent, Chair

Bishop of Pueblo
Diocese of Pueblo

+Most Rev. Arthur N. Tafoya

Smart Growth Advocates

Vickie P Massam, President

Southwest Energy Efficiency Project

____

Howard Geller, Executive Director

Environment Colorado

____

Matt Baker, Executive Director

Sierra Club Rocky Mountain Chapter

____

Susan LeFever, Chapter Director

Colorado Renewable Energy Society

David Bowden, President

Environmental Defense

____
Vickie Patton, Senior Attorney

Western Resource Advocates

____
Jim Martin, Executive Director

PSCo

Richard C. Kelly, President & COO

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Smart Growth Advocates

Vickie P Massam, President

DC01.404628.1

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Vickie Patton

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Jim Martin, Executive Director

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Richard C. Kelly, President & COO

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Computer Modeling Analysis of Proposed LCP Settlement

CPUC Docket No. 04A-214E, 04A-215E, 04A-216E

Jim Hill - Manager Resource Planning
December 3, 2004

Summary

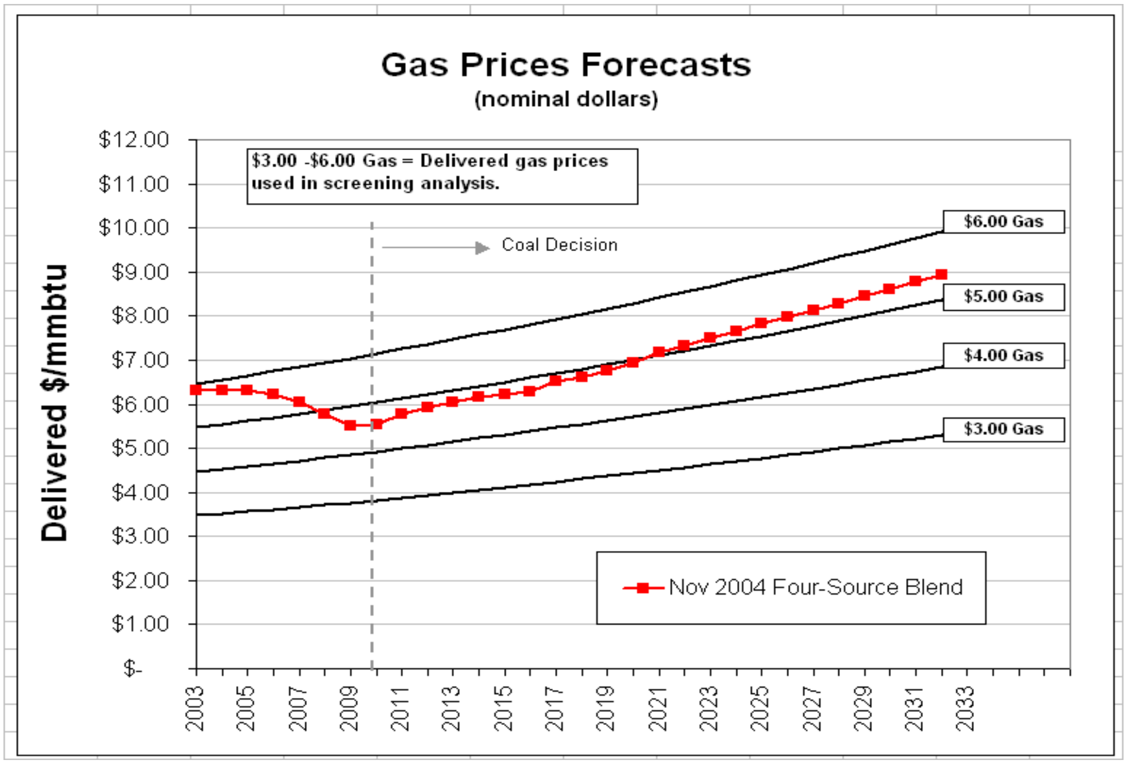
The Strategist computer model was used to examine the cost and average rate impacts of the proposed LCP Settlement under a set of updated modeling assumptions. These included the price forecast for natural gas, PSCo's cost of capital, reserve margins, and the Company's sales forecast. The cost of the Settlement least-cost expansion plan was compared with the cost of other least-cost expansion plans that were developed assuming 1) the Company's position as outlined in its October 18, 2004 rebuttal testimony and 2) Comanche 3 is not constructed.

The results of these model runs indicate that the proposed LCP Settlement is approximately $90 million (2003 PV) lower cost than a least-cost plan based on the Company's rebuttal testimony, and approximately $500 million to $1.3 billion lower cost than a least-cost plan based on revised generic screening runs.

Major Modeling Assumptions

- *Natural Gas Prices*

  Natural gas commodity prices used in this analysis are the same as those used in the Renewable Energy RFP bid evaluation in which a combination of four different long-term gas price forecasts were used to establish a single long-term gas commodity price forecast (CERA, PIRA, EIA, and NYMEX). Additional costs were added to the gas commodity price to account for transportation and Price Volatility Mitigation (PVM). Below is an illustration of the burner tip gas price used in these analyses compared to the range of gas prices used in the LCP screening analysis of Volume 1.



- *Cost of Capital*

  Capital revenue requirements for the Comanche 3 facility, Comanche 1 & 2 emission controls, and for all generic resources were modeled as if they were utility rate-based generation facilities. All revenue requirement calculations were performed using the following information from the 2002 PSCo rate case settlement.

Before Tax Weighted Cost of Capital				After Tax Weighted Cost of Capital		
	Weight	Rate	Wtd Cost	Weight	Rate*	Wtd Cost
Debt	48.60%	7.31%	3.55%	48.60%	4.53%	2.20%
Equity	51.40%	10.75%	5.53%	51.40%	10.75%	5.53%
	Return on Rate Base		9.08%		Discount Rate	7.73%
				* Settlement debt rate times .6199		

- *Reserve Margin*

  All analyses used a minimum reserve margin of 16% of firm load obligation. For all years of the analysis, the maximum allowable reserve margin was set at 25% with the exception of years 2010-2013. For these years, the maximum allowable reserve margin was set at 35% to allow consideration of the large generic coal units.

- *Comanche 3 Modeling (including Emission Controls on Comanche 1&2)*

  The base Comanche 3 facility (i.e., the new 750 MW unit) was modeled consistent with the information contained in LCP Volume 1, Table 1.11-2, column labeled "Comanche 3 Hybrid Cooling". Whenever the base Comanche 3 facility was considered in these modeling analyses, it was accompanied by a set of additional emission controls on existing Comanche units 1&2 (i.e., capital costs, FOM, VOM, emission rate).

  Two sets of Comanche 1&2 emission controls were considered.

  Rebuttal Scenario. This scenario represents the Company's October 18, 2004 rebuttal testimony. Emission controls consist of a new Lime Spray Dryer (LSD) on Comanche 2 for SO2 control and NOx controls on both Comanche units 1&2. A breakdown of how these controls were modeled is as follows:

  - LSD > Capital Cost $47.6 million (2003 $)
    > Annual FOM $1.4 million
    > VOM $0.44/MWh
    > SO2 reduction of 85% (i.e. from 0.59 lbs/mmbtu to 0.09 lbs/mmbtu)
  - NOx > Capital Cost $30 million (2003 $)
    > Annual FOM $0 million
    > VOM $0/MWh
    > NOx reduction of 33% (i.e. from 0.3 lbs/mmbtu to 0.1 lbs/mmbtu)

  Settlement Scenario. This scenario includes all the emission controls and costs of the Rebuttal Scenario plus a new Lime Spray Dryer (LSD) on Comanche 1 and mercury (Hg) controls on both Comanche 1 and 2. A breakdown of how these controls were modeled is as follows:

  - LSD > Capital Cost $47.6 million (2003 $)
    > Annual FOM $1.4 million
    > VOM $0.45/MWh
    > SO2 reduction 85% (i.e. from 0.59 lbs/mmbtu to 0.09 lbs/mmbtu)
  - Hg > Capital Cost $3 million (2003 $)
    > Annual FOM $2 million
    > VOM $0/MWh
    > Hg reduction 60% (i.e. from 0.000005 lbs/mmbtu to 0.000002 lbs/mmbtu)

- *Generic Resources*

  Generic supply-side generation resources were modeled identical to that described in LCP Volume 1, Table 1.10-xx with the following exceptions:

  Wind => To reflect the Company's Renewable Energy RFP, 480 MW of wind (i.e., six of the 80 MW generic wind facilities priced at $30/MWh flat) were added to the existing PSCo system upon which all additional least-cost resource plans were built. An additional 320 MW of wind resources above and beyond the 480 MW were made available to the Strategist model for all runs. Adding this level of wind (480 + 320) to the existing 222 MW of wind currently on the PSCo system represents a penetration of approximately 15%. No additional wind beyond the 15% penetration was allowed in any run. All wind was ascribed a 10% capacity credit.

It was assumed that the additional 320 MW of available wind would not be eligible for the Production Tax Credit (PTC) and would result in higher ancillary service costs than the $2.50/MWh assumed for wind penetration levels to 10%. The additional 320 MW of wind was priced as follows;

Revised Generic Screening and Rebuttal Scenario:

- Assumed PTC price = $27.50/MWh flat
- Assumed PTC = $18.00 MWh
- Non-PTC price = $27.50 + ($18/1-tax rate) = $27.50+ $18/.65 = $55.20/MWh
- Assumed Ancillary Cost = $7.00 MWh (for penetration from 10% to 15%)
- Assumed REC value = $2.13/MWh
- Total Price for additional wind = $55.20/MWh + $7.00/MWh - $2.13/MWh **= $60.06/MWh**

Settlement Scenario:

- Assumed PTC price = $27.50/MWh flat
- Assumed PTC = $18.00 MWh
- Non-PTC price = $27.50 + ($18/1-tax rate) = $27.50+ $18/.65 = $55.20/MWh
- Assumed Ancillary Cost = $7.00 MWh (for penetration from 10% to 15%)
- Assumed REC value = $8.75/MWh
- Total Price for additional wind = $55.20/MWh + $7.00/MWh - $8.75/MWh **= $53.44/MWh**

Conventional Gas CT => Allowed as an option for the Strategist model starting in year 2008. Last year available 2015 (when advanced CT assumed to replace it).

Conventional Gas CC => Allowed as an option for the Strategist model starting in year 2008. Last year available 2015.

Advanced Gas CT => Allowed as an option for the Strategist model starting in year 2016. Last year available 2034.

Advanced Gas CC => Allowed as an option for the Strategist model starting in year 2008. Last year available 2034.

Integrated Gasification Combined Cycle (IGCC) => Allowed as an option for the Strategist model starting in year 2009. Last year available 2034.

Coal => Two sizes of generic coal facility were examined in these analyses, a 750 MW unit and a 500 MW unit. A single 750 MW unit was allowed and up to two 500 MW units were allowed. The first year available for the 750 MW unit was 2011 for the "early generic coal" and 2012 for the "base generic coal" scenarios. The first year available for the 500 MW unit was 2012. The last year available for both the 750 MW and 500 MW units was 2013. One superfluous 500 MW unit was also allowed in these analyses (i.e., allowed to be considered in years when there was not a need for additional capacity to meet minimum reserves).

- *Emission Costs*

  Emissions of SO2, NOx, and Hg were modeled with the same Clear Skies Initiative (CSI) assumptions as those discussed in LCP Volume 1, section 1.10. These are as follows:

  - SO2 = $1,000/ton
  - NOx = $1,000/ton
  - Hg = $25 million/ton

  Emissions of CO2 were modeled at two different levels: $6.00 per ton for both the Revised Screening scenarios and the Rebuttal Scenarios, and $9.00 per ton for the Settlement scenario. Both the $6.00 and $9.00 levels escalated annually at a rate of 2.5%. In all scenarios, the first year the CO2 cost was applied was 2010.

- *Demand and Energy Forecast*

  The July 2004 demand and energy forecast was used to represent the "Base" level of peak demand and annual energy for all scenarios examined. This forecast was provided in the Company's 2004 LCP Annual Progress Report filed with the Commission on October 31, 2004. The July 2004 peak demand forecast is approximately 1% higher (i.e., 67 MW) by year 2013 than the peak demand forecast contained in the Company's April 2004 LCP. The July 2004 energy sales forecast is approximately 0.4% lower (i.e., 160 GWh) by year 2013 than the sales forecast contained in the Company's April 2004 LCP.

  When modeling different levels of DSM in these analyses, the peak demand reductions and energy reductions were applied to the July 2004 demand and energy forecast.

- *DSM Peak and Energy Reductions*

  Three levels of additional DSM were examined.

  1.) No additional DSM => The level of DSM embedded in the July 2004 forecast was all that was considered.

  2.) Rebuttal Scenario DSM => In this scenario, by year 2010 the base peak demand forecast was reduced by 153 MW and annual energy sales were reduced by 365 GWh. These DSM peak and energy savings were assumed to have a fifteen-year life.

  3.) Settlement Scenario DSM => In this scenario, by year 2013 the base peak demand forecast was reduced by 320 MW and annual energy sales were reduced by 800 GWh. These DSM peak and energy savings were assumed to have a fifteen-year life.

Year	Rebuttal DSM Scenario Peak Reductions MW	Rebuttal DSM Scenario Annual Energy Reductions GWh	Settlement DSM Scenario Peak Reductions MW	Settlement DSM Scenario Annual Energy Reductions GWh
2006	25.8	50.2	40	100
2007	54.1	111.1	80	200
2008	85.3	186.2	120	300
2009	119.5	275.6	160	400
2010	153.7	365.0	200	500
2011	153.7	365.0	240	600
2012	153.7	365.0	280	700
2013	153.7	365.0	320	800
2014	153.7	365.0	320	800
2015	153.7	365.0	320	800
2016	153.7	365.0	320	800
2017	153.7	365.0	320	800
2018	153.7	365.0	320	800
2019	153.7	365.0	320	800
2020	153.7	365.0	320	800
2021	127.9	314.8	280	700
2022	99.6	253.9	240	600
2023	68.4	178.8	200	500
2024	34.2	89.4	160	400
2025	0	0	120	300
2026	0	0	80	200
2027	0	0	40	100
2028	0	0	0	0
2029	0	0	0	0
2030	0	0	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0

- *DSM Costs*

The expenditures and associated revenue requirements for the Rebuttal and Settlement levels of DSM discussed above are as follows:

Year	Rebuttal DSM Scenario Expenditures 2004 Dollars $Millions	Rebuttal DSM Scenario Expenditures Nominal Dollars $Millions	Settlement DSM Scenario Expenditures 2005 Dollars $Millions	Settlement DSM Scenario Expenditures Nominal Dollars $Millions
2006	$16.00	$16.76	$17.31	$17.72
2007	$17.40	$18.66	$19.37	$20.29
2008	$19.00	$20.86	$22.97	$24.63
2009	$20.40	$22.92	$24.98	$27.42
2010	$22.20	$25.53	$25.97	$29.18
2011			$27.71	$31.88
2012			$28.84	$33.95
2013			$28.85	$34.77
Total	**$95.00**	**$104.74**	**$196.00**	**$219.85**

Revenue requirements calculations assumed 85% of the above expenditures were capital related and 15% administrative. Capital expenditures for the Rebuttal DSM Scenario were amortized over <u>five</u> years, while capital expenditures for the Settlement DSM Scenario were amortized over <u>eight</u> years. Revenue requirements for both scenarios were calculated assuming a 1-year lag between expenditure year and project in-service year, straight-line depreciation, zero AFUDC and an allowed rate of return of 9.08%. The resulting revenue requirements for both DSM scenarios are as follows:

Year	Rebuttal DSM Scenario Capital Revenue Requirements ($000) Nominal	Rebuttal DSM Scenario Administrative Costs ($000) Nominal	**Total Rebuttal DSM Scenario Revenue Requirements ($000) Nominal**	Year	Settlement DSM Scenario Capital Revenue Requirements ($000) Nominal	Settlement DSM Scenario Administrative Costs ($000) Nominal	**Total Settlement DSM Scenario Revenue Requirements ($000) Nominal**
=======	=======	=======	=======	=======	=======	=======	=======
2003	$0	$0	**$0**	2003	$0	$0	**$0**
2004	$0	$0	**$0**	2004	$0	$0	**$0**
2005	$0	$0	**$0**	2005	$0	$0	**$0**
2006	$0	$0	**$0**	2006	$0	$0	**$0**
2007	$4,014	$2,515	**$6,529**	2007	$3,165	$2,658	**$5,823**
2008	$8,224	$2,799	**$11,023**	2008	$6,618	$3,044	**$9,662**
2009	$12,673	$3,129	**$15,802**	2009	$10,652	$3,695	**$14,347**
2010	$17,293	$3,439	**$20,732**	2010	$14,945	$4,113	**$19,058**
2011	$22,184	$3,830	**$26,014**	2011	$19,287	$4,377	**$23,664**
2012	$17,848	$0	**$17,848**	2012	$23,831	$4,782	**$28,613**
2013	$13,461	$0	**$13,461**	2013	$28,437	$5,093	**$33,530**
2014	$9,006	$0	**$9,006**	2014	$32,862	$5,216	**$38,078**
2015	$4,538	$0	**$4,538**	2015	$28,944	$0	**$28,944**
2016	$0	$0	**$0**	2016	$24,934	$0	**$24,934**
2017	$0	$0	**$0**	2017	$20,683	$0	**$20,683**
2018	$0	$0	**$0**	2018	$16,384	$0	**$16,384**
2019	$0	$0	**$0**	2019	$12,173	$0	**$12,173**
2020	$0	$0	**$0**	2020	$7,969	$0	**$7,969**
2021	$0	$0	**$0**	2021	$3,862	$0	**$3,862**
2022	$0	$0	**$0**	2022	$0	$0	**$0**
Total Rev Req ($000)	$109,241	$15,711	$124,952	Total Rev Req ($000)	$254,746	$32,978	$287,724
Total Rev Req 2003 PV ($000)	$60,603	$9,950	**$70,554**	**Total Rev Req 2003 PV ($000)**	$114,344	$18,455	**$132,799**

- *IPP Contracts Not Extended*

  Least-Cost expansion plans were created with the assumption that no IPP contracts were extended but rather the contracts were assumed to terminate per their current contract term. Generic resources were selected by the Strategist model to replace the capacity lost due to these contract terminations.

- *IPP Contracts Extended*

  Least-Cost expansion plans were also created with the assumption that fifteen existing IPP contracts totaling 2,226 MW were extended. 1,500 MW of these contract extensions occur within the 10-year resource acquisition period of 2003 to 2013. The remaining 726 MW of contract extension occur beyond 2013.

Contract	Summer MW	Termination Year
================	======	======
Thermo Restructuring	150	2009
Brush 2 QF	68	2009
Monfort Greeley QF	32	2011
Brush 1	50	2006
Brush 3	25	2006
Fountain Valley	232	2013
Black Hills Valmont 7&8	80	2013
Black Hills Arap 56	116	2013
Brush 4D	115	2012
ManChief	262	2012
Plains End	111	2012
Blue Spruce	259	2013
subtotal	*1500*	
UNC Greeley QF	69	2014
Rocky Mnt Energy (Calpine)	495	2014
Lamar Wind (1)	162	2019
subtotal	*726*	

Scenarios Modeled

The Strategist planning model was used to develop least-cost expansion plans for the PSCo system over the 2003-2034 time period for three main scenarios:

1.) Revised Screening Scenario - All generic resource technologies are considered for addition to the existing PSCo system (i.e., no Comanche 3). 480 MW of wind @ \$30/MWh included as part of existing PSCo system starting in 2006. Additional 320 MW of wind available for consideration starting in 2007 at a non-PTC price of \$60.06/MWh.

2.) Rebuttal Scenario - Comanche 3 considered along with all generic resources except the generic 750 MW coal unit. DSM peak and energy savings per Rebuttal Scenario (i.e., 153.7 MW and 365 GWh) with associated PVRR of \$70.5 million. 480 MW of wind @ \$30/MWh included as part of existing PSCo system starting in 2006. Additional 320 MW of wind available for consideration starting in 2007 at a non-PTC price of \$60.06/MWh.

3.) Settlement Scenario - Comanche 3 considered along with all generic resources except the generic 750 MW coal unit. Additional DSM peak and energy savings per Settlement Scenario (i.e., 320 MW and 800 GWh) with associated PVRR of \$132.8 million. 480 MW of wind @ \$30/MWh included as part of existing PSCo system starting in 2006. Additional 320 MW of wind available for consideration starting in 2007 at a non-PTC price of \$53.44/MWh.

Least-cost expansion plans for each of these three main scenarios were developed as follows:

The Revised Screening Scenario was examined with both an IPP contract extension scenario and a no-extension scenario under the following six sets of assumptions.

1.)No Additional Pulv Coal - No Additional DSM
2.)Early Generic Pulv Coal (2011) - No Additional DSM
3.)Base Generic Pulv Coal (2012)- No Additional DSM
4.)No Additional Pulv Coal - Rebuttal Scenario DSM
5.)Early Generic Coal (2011) - Rebuttal Scenario DSM
6.)Base Generic Coal (2012) - Rebuttal Scenario DSM

The Rebuttal Scenario was examined with both an IPP contract extension scenario and a no-extension scenario under the following two sets of assumptions.

1.)Comanche 3 in 2010 – Rebuttal Scenario DSM
2.)Comanche 3 in 2012 – Rebuttal Scenario DSM

The Settlement Scenario was examined for both an IPP contract extension scenario and a no-contract extension scenario under the following assumptions.

1.)Comanche 3 in 2010 – Settlement Scenario DSM

Scenario Modeling Results

- *IPP Contracts Not Extended Assumption*

Plan Present Value (PV) Costs and Average Rate Impacts

The Settlement Scenario Least-Cost Expansion plan was approximately $92 million (2003 PV) lower cost than the Rebuttal Scenario and $228 million (2003 PV) lower cost than the Rebuttal Scenario with a two-year delay in the Comanche 3 facility in-service date. The Settlement Scenario was lower cost than the six revised screening runs by $386 million to $1.343 billion (2003 PV). The Settlement Scenario resulted in an increase in average rates of $0.04 /MWh compared to Rebuttal Scenario 1 (i.e., Com 3 in 2010). Compared to all other scenarios, the Settlement Scenario resulted in a decrease in average rates ranging from $0.22/MWh to $2.14/Mwh.

Run Description	Strategist PV $000	DSM Rev Req PV $000	$9 to $6 CO2 Cost Adjustment PV $000	REC Adjustment PV $000	Total Plan Cost PV $000	Cost Delta From Settlement PV $000	Average PV Rate $/MWh
==========	======	======	======	======	======	======	======
Revised Screen 1 = No More Coal - No DSM - Contracts Not Extended	$26,117,310	$0	$0	$0	**$26,117,310**	**$1,343,737**	**$49.84**
Revised Screen 2 = Early Generic Coal - No DSM - Contracts Not Extended	$25,300,200	$0	$0	$0	**$25,300,200**	**$526,627**	**$48.28**
Revised Screen 3 = Base Generic Coal - No DSM - Contracts Not Extended	$25,342,848	$0	$0	$0	**$25,342,848**	**$569,275**	**$48.36**
Revised Screen 4 = No More Coal - Rebuttal DSM - Contracts Not Extended	$25,895,524	$70,554	$0	$0	**$25,966,078**	**$1,192,505**	**$49.77**
Revised Screen 5 = Early Generic Coal - Rebuttal DSM - Contracts Not Extended	$25,089,454	$70,554	$0	$0	**$25,160,008**	**$386,435**	**$48.23**
Revised Screen 6 = Base Generic Coal - Rebuttal DSM - Contracts Not Extended	$25,123,488	$70,554	$0	$0	**$25,194,042**	**$420,469**	**$48.29**
Rebuttal Scenario 1 = Com 3 2010 - Rebuttal DSM - Contracts Not Extended	$24,794,992	$70,554	$0	$0	**$24,865,546**	**$91,973**	**$47.66**
Rebuttal Scenario 2 = Com 3 2012 - Rebuttal DSM - Contracts Not Extended	$24,931,480	$70,554	$0	$0	**$25,002,034**	**$228,461**	**$47.92**
Settlement Scenario = Com 3 2010 - Settlement DSM - Contracts Not Extended	$25,004,572	$132,799	($377,471)	$13,672	**$24,773,573**	**$0**	**$47.70**

CO2 adjustment

The "$9 to $6 CO2 Cost Adjustment" noted in the above table removes the added cost associated with CO2 between the Settlement Scenario and all others. CO2 was priced at $9/ton in the Settlement run and $6/ton in all other runs. The effect of the $9/ton CO2 assumption is embedded within both the least-cost resource mix developed by the Strategist planning model and the "Strategist PV $000" values for the Settlement Scenario (i.e., the $25,004,572). In order to compare the Settlement plan costs which include CO2 @ $9/ton with the other plans that include CO2 @ $6/ton, it is necessary to put all the plan costs on comparable terms. This was accomplished by taking the Settlement plan and recalculating its CO2 costs to reflect a $6/ton CO2 cost rather than a $9/ton cost.

REC adjustment

The "REC Adjustment" noted in the above table accounts for the lower wind cost between the Settlement Scenario and all others. As on page 4 of this report, wind was priced at $53.44/MWh in the Settlement run and $60.06/MWh in all other runs. In order to compare the Settlement plan costs with the other plans that, it is necessary to put all the plan costs on comparable terms. This was accomplished by taking the Settlement plan and recalculating its Non-PTC wind costs to reflect a $60.06/MWh cost.

Least-Cost Resource Mix for 10-Year Acquisition period

The actual mix of resources associated with the various modeling runs discussed above is illustrated below along with each plans total present value of costs over the 2003-2034 time period. For simplicity, only those resources contained within the ten-year resource acquisition period (2003-2013) are shown. The remaining mix of resource additions from 2014 –2034 are not shown; however their costs are included in the 2003-2034 PVRR values. It should also be noted that the PVRR costs shown do not include the adjustments for DSM, CO2 costs, and REC costs.

Year	Revised Screen Run 1 Least-Cost Resource Mix	Revised Screen Run 2 Least-Cost Resource Mix	Revised Screen Run 3 Least-Cost Resource Mix	Revised Screen Run 4 Least-Cost Resource Mix	Revised Screen Run 5 Least-Cost Resource Mix	Revised Screen Run 6 Least-Cost Resource Mix	Rebuttal Scenario Run 1 Least-Cost Resource Mix	Rebuttal Scenario Run 2 Least-Cost Resource Mix	Settlement Scenario Least-Cost Resource Mix
=====	========	========	========	========	========	========	========	========	========
2006	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)
2007	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (3)
2008	A_CC (1)	C_CT (2)	A_CC (1)	C_CC (1)	C_CC (1)	A_CC (1)	C_CT (2)	A_CC (1)	C_CT (2)
2009	IGCC (1)	C_CT (2) A_CC (1)	A_CC (1) C_CT (1)	IGCC (1)	C_CT (1) A_CC (1)	A_CC (1)	C_CT (1) A_CC (1)	A_CC (1)	C_CT (1) A_CC (1) NPTC_W (1)
2010	A_CC (1)	C_CT (3)	C_CC (1) C_CT (2)	A_CC (1)	C_CT (1) C_CC (1)	C_CT (3)	Com_3 (1)	C_CT (3)	Com_3 (1)
2011	A_CC (1)	C_750 (1)	C_CT (2)	C_CT (2)	C_750 (1)	C_CT (3)		C_CT (3)	
2012	C_CC (1) C_CT (4)	C_500 (1)	C_750 (1) C_500 (1)	C_CT (3) A_CC (1)	C_500 (1)	C_CT (1) C_500 (1)	C_500 (1)	Com_3 (1) C_500 (1)	C_500 (1)
2013	C_CT (3) IGCC (1)	C_CT (1) C_500 (1)	C_500 (1)	C_CT (3) IGCC (1)	C_CT (1) C_500 (1)	C_750 (1) C_500 (1)	C_CT (4) C_500 (1)	C_500 (1)	C_CT (3) C_500 (1)
2003-2034 PVRR	**$26,117,310**	**$25,300,200**	**$25,342,848**	**$25,895,524**	**$25,089,454**	**$25,123,488**	**$24,794,992**	**$24,931,480**	**$25,004,572**

PTC_W	= 80 MW PTC Subsidized Wind	**A_CC**	= 368 MW Advanced CC
NPTC_W	= 80 MW Non-PTC Subsidized Wind	**IGCC**	= 506 MW Integrated Gasification CC
C_CT	= 139 MW Conventional CT	**C_500**	= 500 MW Generic Pulverized Coal
C_CC	= 230 MW Conventional CC	**C_750**	= 750 MW Generic Pulverized Coal
A_CT	= 200 MW Advanced CT	**Com_3**	= 750 MW Comanche 3

- *IPP Contracts Extended Assumption*

Plan Present Value (PV) Costs and Average Rate Impacts

The Settlement Scenario Least-Cost Expansion plan was approximately $86 million (2003 PV) lower cost than the Rebuttal Scenario and $362 million (2003 PV) lower cost than the Rebuttal Scenario with a two-year delay in the Comanche 3 facility in-service date. The Settlement Scenario was lower cost than the six revised screening runs by $362 million to $1.257 billion (2003 PV). The Settlement Scenario resulted in an increase in average rates of $0.05 /MWh compared to Rebuttal Scenario 1 (i.e., Com 3 in 2010). Compared to all other scenarios, the Settlement Scenario resulted in a decrease in average rates ranging from $0.48/MWh to $1.98/Mwh.

Run Description	Strategist PV $000	DSM Rev Req PV $000	$9 to $6 CO2 Cost Adjustment PV $000	REC Adjustment PV $000	Total Plan Cost PV $000	Cost Delta From Settlement PV $000	Average PV Rate $/MWh
==========	======	======	======	======	======	======	======
Revised Screen 1 = No More Coal - No DSM - Contracts Extended	$25,341,850	$0	$0	$0	**$25,341,850**	**$1,257,054**	**$48.36**
Revised Screen 2 = Early Generic Coal - No DSM - Contracts Extended	$24,619,014	$0	$0	$0	**$24,619,014**	**$534,218**	**$46.98**
Revised Screen 3 = Base Generic Coal - No DSM - Contracts Extended	$24,809,344	$0	$0	$0	**$24,809,344**	**$724,548**	**$47.35**
Revised Screen 4 = No More Coal - Rebuttal DSM - Contracts Extended	$25,082,704	$70,554	$0	$0	**$25,153,258**	**$1,068,462**	**$48.21**
Revised Screen 5 = Early Generic Coal - Rebuttal DSM - Contracts Extended	$24,375,800	$70,554	$0	$0	**$24,446,354**	**$361,558**	**$46.86**
Revised Screen 6 = Base Generic Coal - Rebuttal DSM - Contracts Extended	$24,573,784	$70,554	$0	$0	**$24,644,338**	**$559,542**	**$47.24**
Rebuttal Scenario 1 = Com 3 2010 - Rebuttal DSM - Contracts Extended	$24,100,194	$70,554	$0	$0	**$24,170,748**	**$85,952**	**$46.33**
Rebuttal Scenario 2 = Com 3 2012 - Rebuttal DSM - Contracts Extended	$24,376,478	$70,554	$0	$0	**$24,447,032**	**$362,236**	**$46.86**
Settlement Scenario = Com 3 2010 - Settlement DSM - Contracts Extended	$24,330,658	$132,799	($378,661)	$0	**$24,084,796**	**$0**	**$46.38**

Least-Cost Resource Mix for 10-Year Acquisition period

The actual mix of resources associated with the various modeling runs discussed above is illustrated below along with each plan's total present value of costs over the 2003-2034 time period. For simplicity, only those resources contained within the ten-year resource acquisition period (2003-2013) are shown. The remaining mix of resource additions from 2014 –2034 are not shown, however, their costs are included in the 2003-2034 PVRR values. It should also be noted that the PVRR costs shown do not include the adjustments for DSM, CO2 costs, and REC costs.

Year	Revised Screen Run 1 Least-Cost Resource Mix	Revised Screen Run 2 Least-Cost Resource Mix	Revised Screen Run 3 Least-Cost Resource Mix	Revised Screen Run 4 Least-Cost Resource Mix	Revised Screen Run 5 Least-Cost Resource Mix	Revised Screen Run 6 Least-Cost Resource Mix	Rebuttal Scenario Run 1 Least-Cost Resource Mix	Rebuttal Scenario Run 2 Least-Cost Resource Mix	Settlement Scenario Least-Cost Resource Mix
=====	========	========	========	========	========	========	========	========	========
2006	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)
2007	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (3)	C_CT (3)	C_CT (3)	C_CT (3)	C_CT (3)	C_CT (3)
2008	C_CC (1)	C_CC (1)	A_CC (1)	C_CC (1)	C_CT (2)	A_CC (1)	C_CT (2)	A_CC (1)	C_CT (2)
2009	IGCC (1)	C_CT (1)	A_CC (1)	IGCC (1)	C_CT (1)	A_CC (1)	C_CT (3)	A_CC (1)	A_CC (1)
		A_CC (1)			A_CC (1)				
2010	C_CC (1)	C_CC (1)	C_CT (2)	C_CT (1)	C_CT (1)	C_CT (2)	Com_3 (1)	C_CC (1)	Com_3 (1)
2011	A_CC (1)	C_750 (1)	C_CT (2)	A_CC (1)	C_750 (1)	C_CT (2)		C_CT (2)	
2012		C_500 (1)	C_750 (1)		C_500 (1)	C_750 (1)	C_500 (1)	Com_3 (1)	C_500 (1)
2013	IGCC (1)	C_500 (1)	C_500 (1)	A_CC (1)	C_500 (1)	C_500 (1)	C_500 (1)	C_500 (1)	C_500 (1)
2003-2034 PVRR	**$25,341,850**	**$24,619,014**	**$24,809,344**	**$25,082,704**	**$24,375,800**	**$24,573,784**	**$ 24,100,194**	**$ 24,376,478**	**$24,330,658**

PTC_W	= 80 MW PTC Subsidized Wind	**A_CC**	= 368 MW Advanced CC
NPTC_W	= 80 MW Non-PTC Subsidized Wind	**IGCC**	= 506 MW Integrated Gasification CC
C_CT	= 139 MW Conventional CT	**C_500**	= 500 MW Generic Pulverized Coal
C_CC	= 230 MW Conventional CC	**C_750**	= 750 MW Generic Pulverized Coal
A_CT	= 200 MW Advanced CT	**Com_3**	= 750 MW Comanche 3