

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 10M-245E

IN THE MATTER OF COMMISSION CONSIDERATION OF PUBLIC SERVICE COMPANY OF COLORADO’S PLAN IN COMPLIANCE WITH HOUSE BILL 10-1365, “CLEAN AIR-CLEAN JOBS ACT.”

**FINAL ORDER ADDRESSING
EMISSION REDUCTION PLAN**

Mailed Date: December 15, 2010
Adopted Date: December 9, 2010

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I. BY THE COMMISSION**A. Statement**

1. This matter comes before the Commission for consideration of an emission reduction plan filed by Public Service Company of Colorado (Public Service or Company) pursuant to House Bill (HB) 10-1365.

2. At the highest level, HB 10-1365 reflects the General Assembly's belief that Colorado will realize significant economic and public health benefits by addressing emissions from front-range coal-fired power plants in a coordinated fashion. Having made this determination that a comprehensive emission reduction strategy is in the public interest, the legislature tasked the Commission and other state agencies with vetting and shaping the plans proposed by regulated electric utilities.

3. Public Service filed its proposed emission reduction plan on August 13, 2010. HB 10-1365 requires the Commission to "review the plan and enter an order approving, denying, or modifying the plan by December 15, 2010." § 40-3.2-205(2), C.R.S. Having conducted a hearing on the plan and fully considered the facts and arguments before us, the Commission hereby modifies and approves Public Service's plan.

B. House Bill 10-1365 and Docket No. 10M-245E**1. The Clean Air – Clean Jobs Act**

4. On April 19, 2010, Governor Ritter signed into law HB 10-1365, commonly known as the "Clean Air – Clean Jobs Act." To assist in achieving the state's air quality goals, HB 10-1365 requires Public Service to submit an emission reduction plan addressing a minimum of 900 megawatts of its coal-fired generation no later than August 15, 2010. § 40-3.2-204(1), C.R.S. This plan must "include a schedule that would result in full implementation of the plan on or before December 31, 2017." § 40-3.2-204(2)(c), C.R.S. The Commission must then

undertake an evidentiary hearing before entering an order “approving, denying, or modifying the plan by December 15, 2010.” § 40-3.2-205(2), C.R.S. If the plan or some modified version of the plan is approved by the Commission, the plan is subject to further review by the Colorado Department of Public Health and Environment (CDPHE). The Air Quality Control Commission (AQCC), a division of the CDPHE, undertakes a proceeding to incorporate the air quality provisions of the approved plan into the regional haze element of the State Implementation Plan (SIP) Colorado will soon be filing with the Federal Environmental Protection Agency (EPA) pursuant to the Federal Clean Air Act (CAA).

5. HB 10-1365 therefore sets forth independent and complementary roles for the CDPHE and this Commission. Because the relationship between the CDPHE and this Commission has been subject to some debate in these proceedings, we will briefly address this issue as a preliminary matter.

2. Role of the CDPHE

6. The CDPHE plays an integral role in both the implementation of HB 10-1365 and in this Docket. First, prior to submitting its proposed plan, Public Service is required to consult and work in good faith with the CDPHE to design a plan that meets the current and reasonably foreseeable emission reduction requirements in a cost-effective and flexible manner. § 40-3.2-204(2)(b)(I), C.R.S.

7. Then, after the proposed plan is submitted, the CDPHE is required to offer its perspective on the plan to the Commission. The Commission is directed to provide an opportunity for the CDPHE to comment on the air quality and emission reductions of the plan, and to evaluate whether the plan is consistent with reasonably foreseeable requirements of the CAA. § 40-3.2-204(2)(b)(II), C.R.S. This determination is critical because the Commission

shall not approve a plan unless the CDPHE has determined that the plan is consistent with the reasonably foreseeable requirements of the CAA. § 40-3.2-204(2)(b)(IV), C.R.S. In preparing these comments, the CDPHE is also required to make a determination as to “whether any new or repowered electric generating unit proposed under the plan, other than a peaking facility utilized less than twenty percent on an annual basis or a facility that captures and sequesters more than seventy percent of emissions not subject to a national ambient air quality standard or a hazardous air pollutant standard, will achieve emission rates equivalent to or less than a combined-cycle natural gas generating unit.” § 40-3.2-204(2)(b)(III), C.R.S.

8. Further, when evaluating the plan, the Commission is required to consider whether the CDPHE believes the plan is likely to achieve at least a 70 percent reduction in oxides of nitrogen (NOx). § 40-3.2-205(1)(a), C.R.S. In making a determination as to achievable emissions reductions, the CDPHE is required to consider emissions from coal-fired power plants identified in the plan that will continue to operate with emission control equipment, as well as emissions from any facilities constructed as replacement capacity. *Id.*

9. Finally, the CDPHE’s opinion regarding what emission reduction requirements are reasonably foreseeable limits the modifications the Commission may adopt in approving the final plan. Section 40-3.2-205(2), C.R.S., provides “[a]ny modifications required by the commission shall result in a plan that the [CDPHE] determines is likely to meet current and reasonably foreseeable federal and state clean air act requirements.”

3. Role of the Commission

10. After preparing its proposed plan in coordination with the CDPHE, Public Service is required to file the plan with this Commission for approval. At a high level, the Commission’s role is to ensure the Company’s plan achieves the necessary emissions reductions in a reasonable

and cost-effective manner. Additionally, the Commission is tasked with ensuring the plan meets the minimum standards of HB 10-1365, such as satisfaction of the full implementation deadline of December 31, 2017, as set forth in § 40-3.2-204(2)(c), C.R.S. In order to make these determinations, the Commission is required to conduct an evidentiary hearing. § 40-3.2-204(2)(b)(IV), C.R.S.

11. HB 10-1365 identifies nine specific factors the Commission must consider in evaluating the plan: (1) whether the CDPHE has determined the plan is likely to achieve at least a 70 percent reduction in NO_x; (2) whether the CDPHE made a determination under § 40-3.2-204(2)(b)(III); (3) the degree to which the plan will result in reductions in other air pollutant emissions; (4) the degree to which the plan will increase utilization of existing natural gas-fired generation; (5) the degree to which the plan enhances the utility's ability to meet state or federal clean energy requirements, relies on energy efficiency, or relies on other low-emitting resources; (6) whether the plan promotes Colorado economic development; (7) whether the plan preserves reliable electric service; (8) whether the plan is likely to protect Colorado customers from future cost increases, including costs associated with reasonably foreseeable emission reduction requirements; and (9) whether the cost of the plan results in reasonable rate impacts, particularly on low-income customers. § 40-3.2-205(1)(a), C.R.S.

12. The plan must also set forth associated costs. § 40-3.2-204(2)(d), C.R.S. The Company is "entitled to fully recover the costs that it prudently incurs in executing an approved emission reduction plan, including the costs of planning, developing, constructing, operating, and maintaining any emission control or replacement capacity constructed pursuant to the plan, as well as any interim air quality emission control costs the utility incurs while the plan is being implemented." § 40-3.2-207(1)(a), C.R.S. The Commission is tasked with evaluating the

reasonableness of costs associated with the plan, as well as the mechanisms by which costs will be recovered.

13. Additionally, HB 10-1365 permits the Company to enter into long-term gas supply agreements to implement the plan. § 40-3.2-206(4), C.R.S. The Commission must review any proposed agreement, and determine “whether the utility acted prudently by entering into the specific agreement, whether the proposed agreement appears to be beneficial to consumers, and whether the agreement is in the public interest.” *Id.*

14. The Commission is required to issue a final order addressing these elements and approving, denying, or modifying the plan no later than December 15, 2010. § 40-3.2-205(2), C.R.S.

4. Role of the AQCC

15. The AQCC is required to initiate a proceeding “to incorporate the air quality provisions of the utility plan into the regional haze element of the [SIP].” § 40-3.2-208(2)(a), C.R.S. This proceeding can only occur after notice and an opportunity for public participation. § 40-3.2-208(2)(c), C.R.S. The AQCC may act on the plan only after the Commission has approved it. § 40-3.2-208(2)(a), C.R.S.

16. If the Commission does not timely approve a plan, if the Company withdraws its plan, or if the final approved plan is rejected by the AQCC, HB 10-1365 establishes an alternative procedure: the AQCC is required to vacate the entire proceeding related to the Company’s plan and initiate a new proceeding for the consideration of alternative proposals for

the appropriate controls of those units covered by the Company's plan. § 40-3.2-208(2)(b), C.R.S.

5. Further Action Under HB 10-1365

17. After the Company's plan has been approved by the Commission and further approved by the AQCC, it proceeds to the General Assembly for consideration as part of the Colorado SIP related to regional haze, which is then submitted to the EPA. If the final approved provisions of the SIP are not consistent with the air quality provisions of the plan the Commission approved, the Company may file a revised plan with the Commission that modifies the original plan to obtain consistency with the SIP. § 40-3.2-208(3), C.R.S.

C. Procedural Summary

1. Procedural Milestones

18. The Commission opened this Docket by Decision No. C10-0452, mailed on May 7, 2010. Decision No. C10-0452 served as the initial notice, provided an opportunity for interested parties to file petitions for leave to intervene, and established a preliminary procedural schedule. Decision No. C10-0452 also identified a unique role for Staff of the Commission (Staff) in this proceeding, characterizing their expected participation as "relatively neutral yet active, providing the Commission with an analysis of the proffered Plan, alternative plans, and responses." ¶ 24. Additionally, Decision No. C10-0452 ordered Public Service to produce certain documents and records that would be helpful in developing the record in this case. *Id.* at ¶ 28. Further, in paragraph 38 of that decision, we permitted "[i]nterested persons, including non-parties," to "file written requests with the Commission asking that the Commission order

Public Service to produce additional documents” pursuant to the Commission’s statutory audit power. *See* § 40-6-106, C.R.S. These requests became known as “paragraph 38 data requests.”¹ *See, e.g.*, Decision Nos. C10-0596, C10-0639, C10-0678, C10-0850. In establishing this data request process, the Commission intended to accommodate the short timelines of this Docket by permitting intervenors to begin developing their cases prior to the August 15, 2010 filing deadline.

19. By Decision No. C10-0545, mailed on June 3, 2010, the Commission noted interventions by right and found good cause to grant petitions to intervene by permission filed by the following entities:

- American Coalition for Clean Coal Electricity (ACCCE);
- Anadarko Energy Services Company (Anadarko);
- Associated Governments of Northwest Colorado (AGNC);
- Blanca Ranch Holdings, LLC and Trinchera Ranch Holdings, LLC, jointly;
- Board of County Commissioners of Weld County, Colorado;
- Boulder County and the City of Boulder, jointly² (collectively, Boulder);
- City and County of Denver (Denver);
- Climax Molybdenum Company and CF&I Steel, L.P., jointly (collectively, CF&I/Climax);
- CDPHE;
- Colorado Energy Consumers;
- Colorado Governor’s Energy Office (GEO);
- Colorado Independent Energy Association (CIEA);
- Colorado Interstate Gas Company (CIG) and Wyoming Interstate Company, LLC, jointly;

¹ Public Service sought an alteration of this data production procedure in its Motion for Reconsideration and/or Clarification of Commission Decision No. C10-0452, filed on May 18, 2010. The paragraph 38 procedure was upheld in Decision No. C10-0638, at ¶ 77.

² In Decision No. C10-0545, we encouraged the City of Boulder and Boulder County to voluntarily withdraw their virtually identical petitions to intervene and to re-file as a joint party. ¶ 6. Boulder County and the City of Boulder filed a Petition to Join the Approved Interventions on June 16, 2010, which was granted in Decision No. C10-0659.

- Colorado Mining Association (CMA);
- Colorado Office of Consumer Counsel (OCC);
- Colorado Oil & Gas Association (COGA);
- Colorado Solar Energy Industries Association (CoSEIA);
- Colorado Springs Utilities and Tri-State Generation and Transmission Association, Inc., jointly (collectively, CSU/Tri-State);
- Federal Executive Agencies;
- Ms. Leslie Glustrom, *pro se*;
- Holy Cross Electric Association, Inc. (Holy Cross);
- Intermountain Rural Electric Association;
- Interwest Energy Alliance;
- Mr. Ronal Larson, *pro se*;
- Noble Energy, Inc., Chesapeake Energy, Inc., and Encana Corporation³ (collectively, Gas Intervenors);
- Peabody Energy Corporation (Peabody);
- School District No. 1, in the City and County of Denver, State of Colorado;
- Southwest Generation (Southwest);
- Staff;
- Suncor Energy (U.S.A.), Inc. (Suncor);
- Thermo Power & Electric LLC (Thermo);
- Wal-Mart Stores, Inc. and Sam's West Inc., jointly (collectively, Wal-Mart);
- Western Fuels – Colorado and Colorado Rural Electric Association, jointly; and
- Western Resource Advocates (WRA).

20. Further, we found good cause to grant the following petitions to participate in this

Docket as *amici curiae*:

- Colorado Renewable Energy Society;
- Energy Outreach Colorado;
- Independence Institute;
- Industrial Energy Consumers of America; and
- Luca Technologies.

³ Although the Gas Intervenors intervened jointly, we treated them as three distinct parties to this proceeding for purposes of discovery. Decision No. C10-0969, at Ordering ¶ 2.

21. The Commission held a pre-hearing conference on May 27, 2010, which was memorialized in Decision No. C10-0638 mailed on June 23, 2010. In that Decision, we further clarified Staff's role in this proceeding and discussed the terms under which Staff would be permitted to utilize a consultant to aid in its analysis of the complex issues in this Docket.⁴ In Decision No. C10-0638 we set limits on the amount and timing of acceptable discovery in this Docket and established additional hearing dates. Decision No. C10-0638 also addressed the process by which Public Service was to develop its August 13, 2010 filing, which is discussed in more detail below.

22. In Decision No. C10-0808, mailed July 30, 2010, the Commission established a process by which motions for extraordinary protection would be resolved by an Administrative Law Judge. We also altered the procedural schedule by, among other things, establishing a date and time for a public comment hearing to be held in Denver, Colorado.

23. Further, Decision No. C10-0808 denied a Notice for Withdrawal of Petition for Intervention filed by the CDPHE. In making that determination, the Commission found the CDPHE was a necessary party in this docket, and that its absence would render the Commission unable to resolve the matters before it. However, in order to accommodate the CDPHE's unique role, the Commission delayed the date after which the CDPHE would be subject to discovery. *See* Decision No. C10-0808, at ¶¶ 48-57.

24. By Decision No. C10-0858, mailed on August 9, 2010, we held the CDPHE would be permitted to file its official report analyzing Public Service's plan no later than

⁴ Staff utilized two consultants in this proceeding. The Harris Group, Inc., provided testimony regarding retrofit feasibility, constructability, retrofit cost estimates, and replacement generation cost estimates. Dr. Harvey Cutler, a professor of Economics at Colorado State University, assessed the statewide economic impacts of the proposed plan.

September 17, 2010, the deadline for answer testimony. However, we requested the CDPHE to submit a filing on August 13, 2010 concerning the criteria it was using to assess the plan's compliance with reasonably foreseeable emissions reductions requirements. We further addressed the contents of the CDPHE's September 17, 2010 report in Decision No. C10-0874, mailed on August 11, 2010, by ordering the CDPHE to address, in part, the scenario identified as "Benchmark 1.1."⁵

25. In Decision No. C10-0874, we also established a public comment hearing to be held in Grand Junction, Colorado.

26. Public Service filed its proposed emission reduction plan on August 13, 2010. The plan contained nine potential emissions reduction scenarios (Benchmark 1.0, Benchmark 1.1, and Scenarios 2, 3, 4, 5, 6, 6.1, and 7) as well as nine replacement generation portfolios (A through I), and a variety of "bolt-on" analyses. In its August 13, 2010 filing, Public Service identified its preferred scenario as scenario 6.1, with replacement portfolio E. *See* § 40-3.2-206(2), C.R.S. (requiring the utility to identify what it believes is the "best way of timely meeting the emission reduction requirements" under the circumstances). This scenario was commonly referred to as "scenario 6.1E" or the Company's "preferred plan."

27. The Commission re-noticed these proceedings on August 18, 2010 in a "Notice of Filing," in order to specifically notice the proposed plan as filed by Public Service. The Notice of Filing referred to a request "for approval of an emission reduction plan, for approval of a long term gas contract, and for approval of a new rate adjustment clause, called the Emissions Reduction Adjustment (ERA)" and specifically referenced that the proposed emission reduction

⁵ Benchmark 1.1 is an alternative all-controls scenario, which excludes Pawnee. *See* Decision No. C10-0808 at ¶ 27.

plan was being filed in accordance with HB 10-1365. The Notice of Filing further established a second period for interventions. No additional petitions for intervention were filed during this second period.

28. On August 30, 2010, the Commission held a public comment hearing in Grand Junction, Colorado.

29. By Decision Nos. R10-0872-I, R10-0897-I, C10-0910, C10-0944, C10-0957, C10-0976, and C10-1021, the Commission addressed the treatment of confidential and highly confidential information in this Docket. *See also* Decisions No. C10-1040 and C10-1079. We determined that Staff and the OCC would be permitted access to the long-term gas contract between Public Service and Anadarko.⁶ Additionally, we held natural gas and coal suppliers would not have access to bids for long-term gas supplies submitted in response to Public Service's May Request for Proposals (RFP). All other parties, excluding Staff and the OCC, were permitted access by outside counsel and outside consultants on an *in camera* basis. We held COGA, CIEA, Southwest, and Thermo would not have access to detailed cost estimates concerning Public Service's proposed replacement generation. However, Staff and the OCC would have unlimited access to this material, and all other parties were permitted access on an *in camera* basis. We also held COGA, Southwest, and Thermo would not have access to offers from Independent Power Producers (IPPs) to sell their facilities and any related letters of intent or other agreements. We further supplemented this Decision to prevent CSU/Tristate, Holy Cross, CoSEIA, Suncor, Boulder, and AGNC from accessing this information. *See* Decision No. C10-1021. For other parties, excluding Staff, the OCC, and WRA, outside counsel and

⁶ This holding was upheld in Decision No. C10-1009.

outside consultants or experts were allowed access to this material on an *in camera* basis. Finally, we held the Company's STRATEGIST⁷ input files were highly confidential, and that access to those files would be limited to Staff and the OCC. However, we did allow discovery concerning the STRATEGIST inputs.

30. Parties submitted answer testimony on September 17, 2010. The CDPHE also submitted its report in the form of answer testimony on September 17, 2010.

31. By Decision No. C10-1036, mailed on September 23, 2010, we permitted Public Service to file supplemental direct testimony in support of its long-term gas contract with Anadarko. As part of that Decision, we altered the procedural schedule to allow Staff and the OCC to file supplemental answer testimony and for Public Service to file supplemental rebuttal. Further, by Decision No. C10-1098, mailed on October 8, 2010, we granted Anadarko and any other party leave to file supplemental cross-answer testimony regarding the long-term gas contract no later than October 15, 2010.

32. On September 23, 2010, the Commission held a public comment hearing in Denver, Colorado.

33. On September 29, 2010, the Commission addressed a Motion for Partial Summary Judgment in Decision No. C10-1067,⁸ concerning whether the Company's preferred scenario, scenario 6.1E, was in compliance with HB 10-1365. Scenario 6.1E included some actions to be taken after 2017, which the moving parties argued was in violation of the

⁷ STRATEGIST is an electric utility planning model that simulates the economic dispatch of the generating resources in Public Service's system in the lowest cost manner. STRATEGIST can assist in the selection of new resources, either to replace retired units or to meet future load growth. STRATEGIST can also be used to simulate power plant emissions, as well as changes in utility rates and revenue requirements over time.

⁸ This Motion for Partial Summary Judgment was filed by CIEA, Thermo, and Southwest on August 31, 2010.

December 31, 2017 implementation deadline set forth in § 40-3.2-204(2)(c). In Decision No. C10-1067, we interpreted the phrase “full implementation by December 31, 2017” as requiring that all activities necessary to comply with current and reasonably foreseeable emissions requirements be completed prior to January 1, 2018. Decision No. C10-1067 at ¶ 20. We therefore accepted the Company’s representations that its preferred scenario would meet reasonably foreseeable emissions reduction requirements if only those actions scheduled to occur prior to December 31, 2017 were completed. *Id.* at ¶ 22. In other words, we opted to consider only those activities scheduled to occur before 2018 as part of Public Service’s preferred scenario, which we referred to as “truncated.” In Decision No. C10-1067, we asked the CDPHE to file a statement concerning whether, in its opinion, this truncated scenario would be sufficient from an emissions reduction standpoint.

34. On October 4, 2010, the CDPHE filed a responsive pleading, in which it stated the truncated scenario would not meet reasonably foreseeable emissions reduction requirements. This pleading, when combined with the rationale in Decision No. C10-1067, essentially eliminated Scenario 6.1E from the Commission’s consideration. The Commission later upheld this ruling in Decision No. C10-1164, mailed on October 27, 2010. In Decision No. C10-1164, we further held that we would generally defer to the CDPHE in matters pertaining to determining which emissions reduction requirements are reasonably foreseeable, as well as how far into the future such requirements can reasonably be foreseen. *See* ¶ 41.

35. On October 8, 2010, parties submitted cross-answer and rebuttal testimony. Also on October 8, 2010, parties filed supplemental answer testimony regarding the long-term gas contract.

36. On October 15, 2010, parties filed supplemental cross-answer and rebuttal related to the long-term gas contract.

37. At a Pre-Hearing Conference on October 19, 2010, Public Service made an oral motion seeking leave to file supplemental direct testimony that would set forth what it characterized as a cost-effective alternative to scenario 6.1E (scenario 6.2J), that would include the retirement and replacement of Cherokee 4 by 2017, to comply with the requirements we set forth in Decision No. C10-1067. We received a written motion later that same day, which also contained proposed modifications to the procedural schedule to accommodate this supplemental testimony. We granted Public Service's Motion for Leave to File Supplemental Testimony in Decision No. C10-1135, mailed on October 22, 2010, but we declined to actually consider that testimony until we heard from parties regarding the procedural burden it could create.

38. On October 25, 2010, Public Service filed supplemental direct testimony in accordance with its October 19, 2010 motion. That supplemental direct testimony identified some modified scenarios for the Commission's consideration, and identified Scenario 5B as the Company's new recommended scenario.⁹

39. In Decision No. C10-1193, mailed November 4, 2010, we granted Public Service's Motion for Acceptance of Supplemental Testimony. In that Decision, we found that the goals of HB 10-1365 would be best served by the development of a full and complete evidentiary record. We therefore accepted the supplemental testimony and adopted an alteration to the procedural schedule, including additional discovery deadlines and hearing dates, to accommodate the supplemental testimony.

⁹ As its nomenclature suggests, scenario 5B was one of the scenarios originally presented in the Company's August 13, 2010 filing.

40. On October 21, 2010, the Commission undertook consideration of a Motion for Disqualification concerning Chairman Binz and Commissioner Baker filed by CMA on October 12, 2010. We denied the Motion for Disqualification in Decision No. C10-1326 mailed on December 10, 2010.

41. On October 21, 2010, the Commission began hearings in this matter. The first round of hearings was conducted on October 21, 22, 25, 26, 28, 29 and 30, 2010, as well as November 1, 2, and 3, 2010. The Commission instructed parties that the first round of hearings should focus on those elements of the plan, as originally filed, that were not impacted by Public Service's supplemental direct testimony.¹⁰ Parties were instructed they would have an additional opportunity to cross-examine witnesses on the supplemental testimony, as well as on the Company's new recommended scenario.

42. Parties filed supplemental answer testimony on November 9, 2010.

43. Parties filed supplemental rebuttal and cross-answer testimony on November 15, 2010.

44. On November 18, 2010, the Commission began the second round of hearings in this matter. The second round of hearings was conducted on November 18, 19, and 20, 2010.

45. The Commission undertook deliberations in this Docket on December 6, 8, and 9, 2010.

¹⁰ Some of the issues parties covered in these days of hearings were: fuel costs, foreseeable emission costs, existing scenarios, the long-term gas contract, and cost recovery.

2. Due Process

46. Throughout these proceedings, a number of parties have raised broad due process arguments.¹¹ Although no party has directly stated as much, many of these pleadings appear to assert constitutional procedural due process arguments, by either invoking the United States Constitution, or by citing to cases concerning constitutional procedural due process.¹²

47. Both the federal and Colorado constitutions prohibit governmental actions that deprive individuals of liberty or property without “due process of law.” U.S. CONST. amend. V and XIV; Colo. CONST. Art. II §25. To raise a successful due process claim, a party must first identify the protected liberty or property interest at stake. *See Goss v. Lopez*, 419 U.S. 565, 572-76 (1975). Once a party has established that procedural due process applies, a court must determine what process is due. *Morrissey v. Brewer*, 408 U.S. 471, 480 (1972). Standards of due process are flexible and will depend on the situation. *Cafeteria Workers v. McElroy*, 367 U.S. 886 (1961). At a minimum, procedural due process requires “notice and an opportunity to be heard in a meaningful manner.” *Nichols ex. rel. Nichols v. DeStefano*, 70 P.3d 505, 507 (Colo. App. 2002) (citing *Goss*, 419 U.S. 565).

48. At no point in these proceedings did any party articulate a liberty or property interest of which it would be deprived. Therefore, the standards of procedural due process, as set

¹¹ *See, e.g.*, Peabody Motion to Vacate Procedural Schedule and Set a Status Conference, filed October 18, 2010; Response of CIEA and Thermo to the Motion of Public Service for Leave to File Additional Testimony, filed October 27, 2010; Gas Intervenors Response to “Motion of Public Service Company of Colorado for Acceptance of Supplemental Testimony” and Response Pursuant to Commission Decision C10-1135, filed October 27, 2010; and Peabody Motion for Summary Judgment, filed October 29, 2010.

¹² *See, e.g.*, Peabody Motion for Summary Judgment, at 21 (citing U.S. CONST. amend. V and XIV); Response of CIEA and Thermo to the Motion of Public Service for Leave to File Additional Testimony, filed October 27, 2010, at 7 (citing *Denver Welfare Rights Org. v. Pub. Utils. Comm’n*, 190 Colo. 329, 547 P.2d 239 (1976); and *In re Marriage of Salby*, 126 P.3d 291 (Colo. App. 2005)).

forth in U.S. CONST. amend. V and XIV, and Colo. Const. Art. II, § 25, are inapplicable here. *See Public Service Co. of Colo. v. Public Util. Comm'n*, 653 P.2d 1117, 1121 (Colo. 1982).

49. However, the Commission is cognizant of the statutory due process to which parties are entitled. Generally, the Commission is required to “conduct its proceedings in such a manner as will best conduce the proper dispatch of business and the ends of justice.” § 40-6-101(1), C.R.S. Specifically, § 40-3.2-204(2)(b)(IV), C.R.S, provides “[t]he commission shall not approve a plan except after an evidentiary hearing.” The Commission held an evidentiary hearing in this Docket on October 21, 22, 25, 26, 28, 29, 30, 2010, as well as November 1, 2, 3, 18, 19, and 20, 2010. Further, § 40-6-109(1), C.R.S., provides that all intervenors “interested in or affected by any order that may be made” are entitled “to be heard, examine and cross-examine witnesses, and introduce evidence.” The Commission believes that, over the course of these proceedings, all parties have been afforded ample opportunity to present their cases, examine and cross-examine witnesses, and introduce evidence. *See* Decision No. C10-0545 (granting Petitions for Intervention); Decision Nos. C10-0452, C10-0638, and C10-1193 (establishing procedural schedules and hearing dates).

50. In short, the Commission has done everything possible to provide parties the maximum process possible, while still complying with the December 15, 2010 deadline for a final decision, as required by § 40-3.2-205(2), C.R.S. These proceedings have necessarily been time constrained. However, the Commission is permitted to fashion procedural mechanisms, including abbreviated procedures, where necessary to carry out its regulatory function.

51. For example, in *Public Service Co. of Colo. v. Public Util. Comm'n*, intervenors challenged the emergency procedures fashioned by the Commission as violating standards of statutory due process. In that case, Public Service filed advice letters arguing that the Company

was facing a financial emergency that warranted an increase in rates. The Commission suspended the tariffs, conducted three days of limited hearings, and issued a decision approximately a month and a half later. 653 P.2d at 1118. Intervenors in the case argued that the abbreviated nature of the proceeding and the limitation of issues to be considered created a hearing that was not granted at a meaningful time or in a meaningful manner. *Id.* at 1121. Intervenors argued they did not have adequate time to conduct discovery and to procure the expert witnesses they needed, because the hearing began only 16 days after the Commission's order of suspension. *Id.* The Colorado Supreme Court disagreed, finding the Commission struck an appropriate balance between offering procedural protections and ensuring the health of the regulated utility. *Id.* at 1122. The Court further agreed with the Commission that it "would be derelict in its responsibility if it did not fashion the procedural mechanisms available to it so as to minimize, to the extent possible, harmful economic results." *Id.* As the Court concluded, "[p]articipatory values are better served by allowing the commission to conform its procedures to the exigencies of the case before it." *Id.*

52. We believe the reasoning of *Public Service Co. of Colo. v. Public Util. Comm'n* supports the procedural mechanisms the Commission has fashioned in this case.

D. Public Service's Plan and Modification Scenarios

1. Pre-Filing Requirements and Plan Development

53. In Decision No. C10-0638, we discussed the process by which Public Service was to develop the scenarios contained in its August 13, 2010 filing. In that Decision, we declined to adopt any limitations on our authority to consider alternative scenarios and to modify any proffered plan. Decision No. C10-0638, at ¶ 28. To that end, we encouraged Public Service to meet with the parties in a workshop setting to discuss development of the scenarios to be

contained in the Company's proposed emission reduction plan. *Id.* at ¶ 26. We further ordered Public Service to submit a filing outlining the contents of the proposed emission reduction plan, including any alternative scenarios and major modeling assumptions, on July 1, 2010. *Id.* at ¶ 31. Following submission of this filing, we permitted comment from parties regarding the sufficiency of Public Service's plan to date, as well as the extent to which the Company was responsive in accommodating and modeling their suggested alternatives in STRATEGIST.¹³ *Id.* at ¶ 33. In so doing, we sought to provide additional process to parties, by providing them with substantial information prior to the August 15, 2010 filing deadline and allowing an opportunity to assist in the development in Public Service's proposed plan.

54. We conducted a status conference to discuss the Company's July 1, 2010 filing and relevant comments on July 9, 2010. In Decision No. C10-0808, we requested that the Company model in STRATEGIST two additional scenarios: (1) an alternative baseline that excluded the installation of a selective catalytic reduction (SCR) at Pawnee station (Benchmark 1.1); and (2) a variation of one of the Company's proposed scenarios that would contain higher levels of renewable resources, while still maintaining transmission stability (scenario 6H). ¶¶ 27-29. While we declined to order the Company to develop any of the other intervenor-suggested alternatives, we stated, "we will in no way preclude the parties from raising arguments in the course of this proceeding concerning the merits of Public Service's emission reduction plan and the alternatives that the Company may not have fully developed for our consideration." *Id.* at ¶ 30. *See also* Decision No. C10-0874 (addressing motions seeking clarification or alteration of Decision No. C10-0808).

¹³ See footnote 7.

2. Public Service's August 13, 2010 Filing

55. On August 13, 2010, the Company filed its proposed emission reduction plan and supporting direct testimony. *See* Public Service Emissions Reduction Plan (Hrg. Ex. 2). Public Service represented that it developed its plan by: (1) identifying the coal units for consideration in the plan and the actions (retirement, fuel switch, or emissions controls) feasible for each unit; (2) constructing combinations of actions, referred to as scenarios; (3) identifying feasible replacement capacity for retired coal facilities; and (4) estimating costs. *Id.* at 25. The Company also stated it consulted with the CDPHE throughout this process. *Id.*

56. The result was a proposed plan that identified nine scenarios (Benchmark 1.0, Benchmark 1.1, and Scenarios 2, 3, 4, 5, 6, 6.1, and 7) and set forth nine potential portfolios of replacement capacity (A through I). *See Id.* at 44, fig. 5.5. Of the combinations of these options, the Company identified scenario 6.1E as its preference.

57. Scenario 6.1E would retire all of the coal-fired electric generating units at Cherokee Station (Cherokee 1-4) and Valmont 5. Cherokee 1 and 2 would be retired before the end of 2011. Selective Non-Catalytic Reduction (SNCR) controls would be installed at Cherokee 4 in 2012. Before Cherokee 3 would be retired, a new 2X1 combined cycle (CC) natural gas-fired plant would be installed at Cherokee Station. Then, Cherokee 3 would be retired in 2017. A second new 1X1 CC gas plant would come into service in 2022, at which time Cherokee 4 would be retired. Valmont 5 would be retired in 2017. Also, Arapahoe 3 and Cherokee 2 would be converted to synchronous condensers in 2014 and 2012, respectively, and 90 MVAR of capacitor banks would be installed at Arapahoe and Cherokee for reactive voltage support. Arapahoe 4 would be fuel switched to run on gas at the end of 2013.

58. Under scenario 6.1E, 213 MW of coal would be retired by 2013; 551 MW of coal would be retired by 2018;¹⁴ and 903 MW of coal would be retired by 2022.

59. With respect to controls, scenario 6.1E would include SCR controls at the Pawnee Station and at Hayden Station on units 1 and 2. The SCR installation at Pawnee would be completed before the end of 2014 and would be coordinated with the installation of a lime spray dryer (LSD) for reductions in the emissions of SO₂. The SCR installation on Hayden 1 and 2 would be complete by the end of 2015 and 2016, respectively.

3. Partial Summary Judgment and Elimination of Scenario 6.1E

60. On August 31, 2010, CIEA, Thermo, and Southwest (collectively, the IPP Intervenors), filed a Motion for Partial Summary Judgment, arguing the two post-2017 elements of Public Service's plan (construction of the new 1X1 CC unit and retirement of Cherokee 4) rendered it fatally flawed under HB 10-1365. Assuming these post-2017 actions were necessary to meet reasonably foreseeable emission requirements, the IPP Intervenors argued the Commission could not approve scenario 6.1E because it would not meet all reasonably foreseeable emissions reduction requirements by December 31, 2017. *See* §§ 40-3.2-204(2)(b)(IV), -204(2)(c), C.R.S.

61. The Commission agreed with the IPP Intervenors that scenario 6.1E did not satisfy the implementation deadline set forth at § 40-3.2-204(2)(c), C.R.S., in Decision No. C10-1067. We therefore stated we would only consider a truncated version of scenario 6.1E, and asked the CDPHE to opine on whether such a truncated scenario would satisfy reasonably foreseeable emissions requirements. The CDPHE stated it would not. *See* Response of the

¹⁴ The Commission had already approved the early retirement of Arapahoe 3 and 4 by Decision No. C08-0929 in Docket No. 07A-447E mailed on September 19, 2008.

CDPHE to the PUC's September 29, 2010 Order Denying Motion for Summary Judgment, filed Oct. 4, 2010.

62. The Company sought modification of Decision No. C10-1067 on October 5, 2010. The Commission denied Public Service's Motion to Modify Decision No. C10-1067 in Decision No. C10-1164. In that decision, we further stated that we generally deferred to the CDPHE with regard to what emissions reduction requirements were reasonably foreseeable, and stated that we declined to utilize our existing organic authority in any way that would circumvent the December 31, 2017 implementation deadline.

63. As a result of these Decisions, Public Service sought leave to file supplemental direct testimony on October 19, 2010. After fully considering the procedural implications of supplemental testimony, we granted the Company leave to file and accepted the supplemental direct testimony in Decision No. C10-1193.

4. Public Service's October 25 Supplemental Direct Testimony

64. Public Service filed its supplemental direct testimony on October 25, 2010. The supplemental testimony set forth an alternative scenario that achieves retirement of Cherokee 4 by 2017, but also analyzes cost associated with fuel-switching Cherokee 4 to run on natural gas by the end of 2017. Public Service identified these scenarios as scenario 6.2J (retires Cherokee 4 by the end of 2017 and constructs both a 1X1 and a 2X1 CC plant at Cherokee Station before the end of 2017); scenario 6E FS (modifies scenario 6E by fuel switching Cherokee 4 at the end of 2017 and completing the retirement of Cherokee 4 and the construction of a new 1X1 CC plant at Cherokee Station by the end of 2018); and scenario 6.1E FS (modifies scenario 6.1E by fuel switching Cherokee 4 at the end of 2017 and completing the retirement of Cherokee 4 and the construction of a 1X1 CC plant at Cherokee Station by the end of 2022).

65. In addition to identifying these proposed scenario modifications, the Company further stated that scenario 5B was now the Company's recommended scenario.

66. In response to this supplemental direct testimony, the CDPHE filed supplemental answer testimony of Mr. Paul Tourangeau, in which he stated the CDPHE believes the fuel switching scenarios are consistent with current and reasonably foreseeable emissions requirements while achieving the necessary levels of NO_x reductions. *See* Tourangeau Fuel Switching Testimony (Hrg. Ex. 200). The CDPHE believes Scenario 6.2J is similarly consistent with HB 10-1365's air quality provisions. *See* Tourangeau Supplemental Answer Testimony (Hrg. Ex. 201).

5. Public Service's Recommended Scenario

67. Scenario 5B was contained in the Company's August 13, 2010 filing, and was elevated to the status of "recommended" by the Company in its October 25, 2010 supplemental direct testimony. Scenario 5B would retire Cherokee 1 and 2 before the end of 2011 and retire Cherokee 3 and Valmont 5 before the end of 2017. A new 2X1 CC would be installed at Cherokee Station before the end of 2015. Arapahoe 3 and Cherokee 2 would be converted to synchronous condensers in 2014 and 2012, respectively. Further, 90 MVAR of capacitor banks are installed at Arapahoe and Cherokee for reactive voltage support. Arapahoe 4 would be fuel switched to run on gas before the end of 2013.

68. Scenario 5B retires 213 MW of coal by January 1, 2013, and retires a total of 551 MW of coal by January 1, 2018.

69. As originally presented, scenario 5B also included the installation of SCR controls on Cherokee 4 in 2016. However, in its October 25, 2010 supplemental direct testimony, Public Service requested this installation date be changed to 2017. As with all other primary scenarios,

scenario 5B also included SCR and LSD controls at the Pawnee Station and SCR controls on Hayden 1 and 2.

6. Intervenor Presented Alternative Scenarios

70. Certain intervenors prepared alternative scenarios or advocated for specific scenarios modeled in STRATEGIST by Public Service.

71. Those intervenors generally representing coal interests advocated for the adoption of Benchmark 1.0. Benchmark 1.0 is the all controls scenario that the Company must prepare for cost comparison purposes, pursuant to § 40-3.2-206(3)(a), C.R.S. Benchmark 1.0 includes installation of SNCR on Cherokee 1 and 2 and SCRs on Cherokee 3 and 4, Hayden 1 and 2, and Valmont 5. Primarily because of the SNCR installations on Cherokee 1 and 2, which are among the oldest coal-fired units in the Company's generation fleet, and because of the installation of SCR on Cherokee 3, Public Service opposes Benchmark 1.0 and stated it would withdraw its plan under § 40-32-205(4), C.R.S., should the Commission adopt those modifications to the Company's recommended scenario. *See* Public Service Statement of Position (SOP) at 27.

72. By contrast, the Gas Intervenors advocated for a modified version of scenario 7E. As modeled by the Company, scenario 7E would retire all of the Cherokee units and Valmont 5. Cherokee 1 and 2 would be retired at the end of 2011. Cherokee 3 and 4 would be fuel switched from coal to gas in 2014. Cherokee 3 would be retired in 2015 when a new 2X1 CC gas plant would go into operation. Cherokee 4 would be retired in 2018 when a new 1X1 CC gas plant would go into operation. Valmont 5 would be switched to gas in 2013 prior to being retired in 2017. Arapahoe 3 and Cherokee 2 would be converted to synchronous condensers in 2014 and 2012, respectively, and 90 MVAR of capacitor banks would be installed at Arapahoe and

Cherokee for reactive voltage support. Arapahoe 4 would be fuel switched to run on gas at the end of 2013.

73. By way of modifications to the Company's modeled scenario 7E, the Gas Intervenors recommend delaying the decision to build any 1X1 CC to replace Cherokee 4 until either the Company's 2011 Electric Resource Plan (ERP) filing,¹⁵ or until additional transmission studies could be completed. According to the Gas Intervenors, scenario 7E would result in earlier emission reduction benefits with no significant differences in near-term ratepayer impacts as compared to the Company's proposed scenario. *See* Cavicchi Answer Testimony (Hrg. Ex. 73), at 32.

74. The IPP Intervenors support a scenario known as IPP2. Late in these proceedings, the IPP Intervenors reached an understanding with Public Service regarding the development of a STRATEGIST analysis of certain modifications to the Company's emission reduction plan,¹⁶ involving various combinations of re-contracting long-term purchased power agreements (PPAs) with existing natural gas electricity generation units owned by Thermo and Southwest. Based on these STRATEGIST runs, the IPP Intervenors presented and advocated for scenario IPP2. The CDPHE evaluated scenario IPP2 and concluded it was consistent with reasonably foreseeable emissions reduction requirements and achieved the necessary levels of NOx reductions. *See* Tourangeau Testimony Regarding IPP2 (Hrg. Ex. 202).

75. Scenario IPP2 would retire Cherokee 1 and 2 in 2011 and replace Cherokee 2 with a synchronous condenser in 2012. Arapahoe 3 would similarly be retired in 2013 and

¹⁵ The Commission's ERP Rules, set forth at Rule 3600, 4 *Code of Colorado Regulations* (CCR) 723-3, *et seq.*, require Public Service to file an ERP on or before October 31, 2011.

¹⁶ The Commission expects the timing of STRATEGIST runs may be an issue in the Company's next ERP proceeding. As a result, we are interested on gathering information on the timing of STRATEGIST modeling in advance of the Company's next ERP filing.

transformed into a synchronous condenser in 2014, while Arapahoe 4 would be retired in 2013. The Company would renew contracts for 199 MW of replacement power from Southwest and 69 MW from Thermo for service beginning in the 2012 to 2013 timeframe. SCR would be installed on Hayden 1 and 2, and SCR and LSD would be installed on Pawnee. Cherokee 3 and 4 and Valmont 5 would all be retired in 2017, when a new single-cycle combustion turbine (CT) peaker unit at the Cherokee Station would come online. *See* Response to Discovery Request No. CIEA5-1 (Hrg. Ex. 181).

76. In support of scenario IPP2, the IPP Intervenors stressed the lower levels of construction risk associated with the relatively less complicated installation of a CT at Cherokee Station in combination with the use of already built gas-fired generation through PPAs. The IPP Intervenors further argue that the STRATEGIST results likely underestimate the costs of the new Company-built generation facilities and that, from a reliability perspective, it would be preferable to have multiple load-service centers at the Valmont and Arapahoe Stations in addition to Cherokee Station. The IPP Intervenors also suggest that their existing CT facilities are better than the proposed new CC units for system operations. *See, e.g.*, Southwest SOP; Thermo SOP.

77. WRA also presented an alternative scenario in answer testimony. This modified scenario 6H would retire Cherokee 1, 2, 3, and 4 and Valmont 5, all before 2017. A new 2X1 CC gas plant at the Cherokee site would go into operation before the end of 2015, and, only if necessary as a backstop measure, additional replacement capacity would be installed at the Company's Fort Saint Vrain Station. Unlike the other principal scenarios, only Arapahoe 3 would be converted into a synchronous condenser. Voltage support and reactive power needs at Cherokee Station would instead be satisfied with MVAR static VAR compensators (SVCS) or

static synchronous compensators (STATCOMMS). *See* Nielsen Answer Testimony (Hrg. Ex. 92), at 19.

78. WRA supported its modified scenario 6H due to its lower emissions of NO_x, SO₂, CO₂, and mercury, as well as its relatively lower exposure to high coal costs due to earlier coal plant retirements. If monetized health benefits were associated with these incremental emissions benefits, WRA claimed the cost effectiveness of its preferred scenario relative to the Company's recommended scenario would improve. Although WRA supported this modified scenario 6H at the beginning of hearings, its position eventually changed in support of scenario 6.2J. *See* WRA SOP, at 1.

79. Therefore, the Commission's consideration was focused on an evaluation and comparison of its proposed scenario 5B to scenarios Benchmark 1.0, as required by the statute, and scenarios 6E FS, 6.1E FS, 6.2J, 7E, and IPP2.

7. Requested Approvals

80. Public Service sought the following approvals and/or findings in this Docket:

- approval of Scenario 5B as the Company's "recommended" emission reduction plan under HB 10-1365;
- findings that the emissions controls, retirements, and replacements associated with the Company's recommended plan are needed and in the public interest;
- findings that the Company has the flexibility to install the SCR on Cherokee 4 until the end of 2017, if controls are approved for Cherokee 4;
- approval of the fuel switching of Arapahoe 4 so that no challenge to this fuel switching can be made in subsequent adjustment clause reviews;
- approval of the long-term gas purchase agreement with Anadarko¹⁷ under § 40-3.2-206, C.R.S., including findings that the Company acted prudently by entering into this agreement, that the agreement appears to be beneficial to consumers, and that the agreement is in the public interest;

¹⁷ Carter Direct Testimony (Hrg. Ex. 14), Exhibits TJC 3 and TJC 3A.

- a finding that under certain defaults, under the long-term gas contract, replacement gas costs would be recoverable through the fuel clause given prudent contract management;
- recognition by the Commission that the new gas-fired 2X1 CC units at Cherokee Station and any additional natural gas-fired generation located at Cherokee Station will need adequate gas transportation infrastructure and the pipeline will eventually be included in gas rate base with charges to the Company's electric department for service rendered;
- a finding of need for a 2X1 CC at Cherokee Station in order to accelerate a required subsequent proceeding regarding a Certificate of Public Convenience and Necessity (CPCN) for this new generation facility;
- a finding that the Company does not need a CPCN for emissions controls at Pawnee, Hayden, and Cherokee 4, as well as clarification that Rule 3205(b)(II) applies to these projects, deeming them to be in the ordinary course of business;
- a finding that the Company does not need to file a separate application, either for a CPCN or otherwise, to retire units ahead of their useful lives;
- approval in this docket of the early retirements of all existing units affected by the plan scenarios selected by the Commission;
- approval of a specific rate rider, the ERA and associated tariff sheets to allow: (1) current return on capitalized construction work in progress (CWIP) at Public Service's weighted average cost of capital (WACC), including the Company's most recently authorized rate of return on equity (ROE); and (2) recovery of incremental 2011 plant-related costs (for example, accelerated depreciation and removal expenses offset by reduced rate base during 2011) starting January 1, 2011;
- a finding that the Company's plan satisfies the requirement of "early conversion or closure of coal-based generation capacity by January 1, 2015" required by CRS § 40-3.2-207 (4);
- a finding that the Company has demonstrated "that a lag in recovery of the costs of the plan related to the investment required by such plan contributes to a utility earning less than its authorized return on equity" under § 40-3.2-207(4), C.R.S.;¹⁸ and
- a finding that the appropriate share of costs of these plants to seek recovery from wholesale customers is the jurisdictional allocator as it changes over time under § 40-3.2-207(2)(a), so long as the allocator does not conflict with the Company's wholesale contracts executed prior to HB 10-1365.

¹⁸ The Company requests this finding regardless of whether the ERA or deferred accounting is approved for accelerated depreciation and removal costs.

E. Considerations in Evaluating the Plan**1. Reasonable Fuel Cost Forecasts**

81. Section 40-3.2-206(3)(b), C.R.S., requires us to “use reasonable projections of future coal and natural gas costs.” As part of its STRATEGIST modeling, Public Service adopted certain fuel cost assumptions. These modeling assumptions and conventions are based on those the Commission approved in the Company’s most recent ERP. *See* Docket No. 07A-447E.¹⁹ While the methodology for deriving the forecasts is the same, the values have been updated to reflect current data.

a. Gas Price Forecasts

82. In developing its forecast for gas prices, Public Service blends three industry forecasts and a quote of the current market using the closing price on the New York Mercantile Exchange and an adder for estimating gas price volatility. *See* Hrg. Ex. 2, at 16-17. *See also* Public Service SOP, at 51-53. The Company believes this method represents a prudent range of possible future prices. Further, in developing its forecast, the Company incorporated projected savings from the Anadarko long-term gas contract. However, these savings were not credited to the Benchmark 1.0 scenario. *See* Montgomery Cross-Answer Testimony (Hrg. Ex. 45), at 22-23.

83. A number of parties suggest the Commission use a different natural gas price forecast in evaluating the proposed scenarios. *See* Peabody SOP, at 38-39 (contending Public

¹⁹ We took administrative notice of Decision No. C08-0929 in Docket No. 07A-447E. Tr. Oct. 21, 2010, at 146.

Service's forecasted natural gas price is too low); Fishman Answer Testimony (Hrg. Ex. 181) (contending Public Service's forecasted natural gas price is too high).

84. The Commission finds Public Service's method of forecasting natural gas prices is reasonable. However, we do not believe this finding of reasonableness requires us to explicitly adopt Public Service's gas forecasts in evaluating the scenarios before us. Rather, we are mindful of each scenario's relative sensitivity to fluctuations in gas prices, and take this into consideration in determining which scenario is the most reasonable from a cost perspective. We do, however, accept Public Service's predictions regarding gas transportation costs, as we think the Company is in the best position to estimate those costs.

85. Furthermore, we decline to assume any estimated savings as a result of the Anadarko long-term gas contract. As a preliminary matter, we believe any predicted savings that may result from the contract should be applied to all scenarios, including Benchmark 1.0, as Public Service could, under any scenario, benefit from a contract covering a portion of its gas burn. Additionally, the predicted savings associated with the contract are a function of differences in various forecasts and therefore are not likely to be precise. In other words, while we believe the long-term contract offers benefits (which we will discuss further below), we do not believe the Company's projected savings should affect our evaluation of the relative benefits of the scenarios.

b. Coal Price Forecasts

86. Public Service obtains its coal supplies through a combination of term and spot contracts, as well as over-the-counter transactions. The Company developed coal price forecasts based on forecasts from third-party experts combined with known prices from existing contracts. Hrg. Ex. 2, at 16-18. This is similar to the assumptions Public Service made in its 2007 ERP.

However, Public Service did adjust coal prices downward slightly for purposes of its emission reduction plan, as a result of the Wood Mackenzie modeling of the impact the plan itself would have on coal prices. *See* Hrg. Ex. 2, at 140.

87. Some parties suggest the Commission use a different coal price forecast in evaluating the proposed scenarios. *See* Peabody SOP, at 42-43 (contending Public Service’s coal price forecasts are biased); Glustrom SOP, at 12-16 (contending Public Service’s coal price forecasts are too low).

88. The Commission finds Public Service’s method of forecasting coal prices is reasonable. However, again, we do not believe this finding of reasonableness requires us to explicitly adopt Public Service’s coal price forecasts in evaluating the scenarios before us. While coal prices are historically less volatile than natural gas prices, we nonetheless believe coal prices may change significantly. Therefore, as with natural gas, we are mindful of each scenario’s relative sensitivity to fluctuations in coal prices, and take this into consideration in determining which scenario is the most reasonable from a cost perspective.

2. Reasonable Cost Forecasts for Reasonably Foreseeable Emission Regulation

89. Section 40-3.2-206(3)(c), C.R.S., requires us to “incorporate a reasonable estimate for the cost of reasonably foreseeable emission regulation consistent with the Commission’s existing practice.” To implement this provision of HB 10-1365, parties have focused exclusively on costs associated with carbon dioxide and other greenhouse gasses.

90. In Docket No. 07A-447E, the Commission approved a carbon proxy cost of \$20 per ton, escalating at 7 percent per year, beginning in 2010. Decision No. C08-0929, at ¶ 270. In this Docket, Public Service recommends the Commission adopt a \$20 per ton price of

carbon, escalating at 7 percent per year but beginning in 2014. Parties in support of the \$20 per ton proxy price argue it is a price the EPA may reasonably adopt if it chooses to regulate greenhouse gases under § 111(d) of the Clean Air Act. *See* Public Service SOP, at 49. Others argue \$20 per ton represents an internalization of the social costs of carbon emissions that are typically experienced as externalities. *See* WRA SOP, at 25-27. Still others support adopting a \$20 per ton price because the alternative of \$0 per ton is unreasonable. *See* GEO SOP, at 6. Finally, parties argue the Commission should adopt the \$20 per ton prices because it is the price the Commission used in Docket No. 07A-447E and thus, any other price would not be “consistent with the Commission’s existing practice.” *See* Gas Intervenors SOP, at 17.

91. However, a number of parties oppose a \$20 per ton cost of carbon. Peabody presented testimony that the EPA’s imminent regulation of greenhouse gases under the New Source Review provisions of the Clean Air Act would not impose a price per ton of carbon emissions, and that it is unlikely a policy to address climate change will be adopted that includes a price per ton of carbon emitted. Smith Answer Testimony (Hrg. Ex. 50), at 22-24; Tr. Nov. 19, 2010, at 59-62. Further, some parties argue the Commission should adopt a \$0 per ton cost of carbon, because Public Service failed to meet its burden of proof in justifying a \$20 per ton price. *See* Peabody SOP, at 44-49; AGNC SOP, at 14; ACCCE SOP, at 16-18.

92. The Commission has applied a cost to carbon emissions in the Company’s two previous ERPs. *See* Docket Nos. 04A-214E, 04A-215E, 04A-216E, and 07A-447E. Carbon “adders” in this context served as proxies for the expected costs that carbon regulation would impose on various resources over the course of their lifetimes. Modeling a presumed cost of carbon is justified when considering the relative benefits of new utility resources, some of which have useful lives in excess of 40 years. However, the compressed timeframe required by this

Docket, coupled with the uncertainty over how carbon regulation will be manifest, leads us not to adopt a specific “dollars per ton” benchmark for this proceeding. That being said, the Commission observes that EPA regulation of greenhouse gasses is currently underway, future regulation in some form is highly likely, and that those regulations will eventually impose costs on a utility’s greenhouse gas emissions. Therefore, while we do not adopt a specific future cost per ton in evaluating the proposed scenarios, we consider each scenario’s carbon emissions reductions, as well as its sensitivity to carbon prices, as modeled by the Company.

3. Benefits of a Coordinated Emissions Reduction Strategy

93. Section 40-3.2-206(3)(e), C.R.S., requires the Commission to “consider the economic and environmental benefits of a coordinated emissions reduction strategy.”

94. We agree with Public Service that the primary purpose of HB 10-1365 is to encourage the Company to address current and reasonably foreseeable emissions reductions in a coordinated fashion to reduce the overall cost of compliance. *See* Public Service. SOP, at 92. We have therefore considered not only the pattern of estimated costs during the implementation period of the plan, 2011 to 2017, but also the likely occurrence of base rate proceedings by which Public Service would begin to recover the substantial investments associated with emission reduction when these investments go into service.

95. In other words, we have examined the sequencing and level of capital spending over the next seven years in addition to the predicted changes in overall rates from the STRATEGIST model runs in the near term (2011 to 2020) as well as the long term (2011 to 2046). By considering such impacts in a coordinated fashion, we help to ensure the benefits of a coordinated emission reduction strategy consistent with HB 10-1365.

F. Modifications and Approvals**1. Basis for Findings**

96. With the exception of Benchmark 1.0, the scenarios presented by Public Service and the intervening parties share many common elements. All include early retirement of Cherokee 1, 2, and 3; early retirement of Valmont 5; fuel conversion of Arapahoe 4; conversion of Cherokee 2 and Arapahoe 3 into synchronous condensers; controls on Pawnee and Hayden; and replacement generation for Cherokee 1, 2, and 3 plus Valmont 5 in the form of a new 2X1 CC at Cherokee Station.

97. The principal differences between the scenarios involve the disposition of Cherokee 4 (scenarios 5B, 6E FS, 6.1E FS, 6.2J), whether and when to apply fuel conversion of certain coal units to natural gas (scenario 7E), and whether to renew PPAs with certain plants owned by Southwest and Thermo (scenario IPP2).

98. From a cost perspective, the STRATEGIST model runs clearly indicate that the cost of capital construction, the cost of natural gas, and the cost of carbon emissions all significantly contribute to the overall cost of each scenario. *See Hill Supplemental Rebuttal Testimony (Hrg. Ex. 188), at 9.* Even so, the STRATEGIST results for expected rates and revenue requirements, even supplemented with monetized health benefits, do not reveal an easily apparent advantage of one scenario over another. *See Dirmeier Supplemental Answer Testimony (Hrg. Ex. 239), at 6.* In addition, uncertainty surrounding the preliminary estimates of the capital construction costs of the proposed projects, including both controls and new natural gas-fired generation facilities, suggests that during the period between 2011 and 2022, all scenarios could result in roughly the same level of investment costs.

99. According to Staff, the Company's projected costs for a new 2x1 CC at Cherokee Station appear to be low based on other similar facilities with similar equipment, potentially causing an understatement of the total capital costs of the scenarios that include this new facility. Staff also generally concludes that the Company's capital cost estimates may be less accurate than the plus or minus 20 percent that the Company has attached to them. *See* Camp Supplemental Answer Testimony (Hrg. Ex. 203), at 8-9.

100. Public Service acknowledges that the Company has not presented cost estimates as Certificate of Public Convenience and Necessity (CPCN) quality numbers, given the time available and the number of scenarios under consideration. Nevertheless, the Company believes the cost estimates that it presented in this Docket are sufficient for valid comparisons of the scenarios against each other. *See* Public Service SOP, at 61.

101. From an emission reduction perspective, all of the scenarios meet the standard that NO_x emissions will be reduced by 70 to 80 percent. CDPHE SOP, at 9-11. Likewise, the CDPHE has determined that these scenarios will meet reasonably foreseeable requirements of the CAA. *Id.* at 11-12.

102. It is also undisputed that early emission reductions offer potential health benefits to the residents in the Denver metro area. The emission reduction profiles of the various scenarios as developed by STRATEGIST reveal significant differences among the scenarios in NO_x, SO₂, and mercury emissions between 2011 and 2018. Scenarios with relatively more coal burn tend to have higher emissions of NO_x, SO₂, mercury, and CO₂.

103. Largely due to such emission reductions, several parties support the adoption of scenario 6.2J, including WRA, the GEO, Boulder, and, notably, the CDPHE.

104. Finally, from a feasibility perspective, Public Service affirms that all of the scenarios that we are considering can be implemented successfully. *See* Public Service SOP, at 62. However, the only practical options for Cherokee 4, according to the Company, are the installation of SCR at Cherokee 4 by 2017 (scenario 5B), fuel switching Cherokee 4 by 2017 (scenarios 6E FS or 7E), or retiring Cherokee 4 and replacing it with a 1X1 CC or CT (scenario 6.2J or IPP2). Public Service claims that the alternatives to scenario 5B could result in higher rates for customers, but the Company also acknowledges that the balance between short-run price impacts and long-run benefits, including emission reductions, is a close call among these scenarios. *See* Hyde Supplemental Rebuttal Testimony (Hrg. Ex. 184), at 7. Public Service concludes that this Docket is, in essence, a public policy debate over how much to raise electric rates to achieve various levels of emissions reductions. *See* Public Service SOP, at 94.

2. Cherokee 1, 2, and 3

105. Unit 1 at Cherokee Station is a 107 MW coal-fired electric generating facility that began operations in 1957 and whose expected useful life ends in 2017. Unit 2 at Cherokee Station is a 106 MW coal-fired electric generating facility that began operations in 1959 and whose expected useful life ends in 2019. Unit 3 at Cherokee Station is a 152 MW coal-fired electric generating facility that began operations in 1962 and whose expected useful life ends in 2022.

106. Both Cherokee 1 and 2 would be retired in 2011 under Public Service's recommended scenario. SNCR controls would be installed at each unit before the end of 2014 under the Benchmark 1.0 scenario at an estimated cost of approximately \$21.3 million, plus or minus 20 percent. Ford Direct Testimony (Hrg. Ex. 10), at 7-8.

107. With respect to Cherokee 3, Public Service proposes to retire the facility in 2017. SCR controls on the unit would be installed under the Benchmark 1.0 scenario at an approximate cost of \$163 million, plus or minus 20 percent. *Id.* at 9.

108. Because both Cherokee 1 and 2 are more than 50 years old and are approaching the end of their useful life, we conclude that retirement is a superior solution to controls on these units in order to meet reasonably foreseeable emission reduction requirements. Therefore, the Commission finds it necessary and in the public interest to retire Cherokee units 1 and 2 before the end of 2011 for emission reduction purposes.

109. Public Service proposes to convert the retired Cherokee 2 unit into a synchronous condenser before the end of 2012 to provide dynamic VAR support upon the retirement of the coal-fired units at Cherokee Station. The Company estimates that the capital costs associated with this conversion, plus the addition of a 90 MVAR capacitor bank for static VAR support, will be approximately \$4 million, plus or minus 20 percent. *Id.* at 17.

110. We find that the re-use of Cherokee 2 as a synchronous condenser and the additional 90 MVAR capacitor bank to be the most cost effective solution for providing both dynamic and static VAR support at Cherokee Station. In light of the criticism that synchronous condensers may result in higher than expected operating costs in the future, and given the extensive testimony offered in this Docket regarding alternative VAR support technologies such as SVCs, STATCOMMS, and D-VAR systems, we direct Public Service to carefully monitor the use of the synchronous condenser at Cherokee 2 during the implementation period of the plan. As part of future transmission planning activities, the Company should ensure that the synchronous condenser provides the appropriate level of cost-effective VAR support relative to these alternative technologies.

111. We also find retirement of Cherokee 3 to be a better outcome than SCR controls for meeting reasonably foreseeable emission reduction requirements. We recognize that under the Company's proposed scenario (scenario 5B), this unit would be retired in 2017. Public Service explains that retirement in 2017 would allow a period of time for a 2X1 CC to be tested and tuned, for fuel cost savings to be available to ratepayers in 2016 and 2017, and for minimizing the impact of accelerated depreciation in years 2011 through 2017. *See* Hrg. Ex. 184, at 15. However, we are not aware of any operating or construction-related impediments to retirement in 2015 and note that a 2015 retirement for Cherokee 3 was modeled in STRATEGIST for scenarios 6E FS and 7E. The Commission therefore finds it necessary and in the public interest to retire Cherokee 3 before the end of 2015 for emission reduction purposes.

3. Arapahoe 3 and 4

112. Arapahoe 3 is a 45 MW coal-fired electric generation facility that began operations in 1951. Arapahoe 4 is a 111 MW coal-fired electric generation facility that began operations in 1955.

113. By Decision No. C08-0929, the Commission approved the early retirement of both Arapahoe 3 and 4 for emission reduction purposes. Consistent with that previous Decision, Public Service proposes in this Docket to retire Arapahoe 3 before the end of 2013 and to convert the unit into a synchronous condenser. The Company estimates that the capital costs associated with this conversion, plus the addition of a 90 MVAR capacity bank for static VAR support, will be approximately \$4.9 million, plus or minus 20 percent. Hrg. Ex. 10, at 17. The Company no longer plans to retire Arapahoe 4 but instead proposes that it be converted from coal-fired generation to run on natural gas before the end of 2014.

114. The Commission determines that because Arapahoe 3 is approaching the end of its useful life, retirement is necessary and in the public interest consistent with our previous determination in Docket No. 07A-447E. Also, consistent with our findings regarding the conversion of Cherokee 2, we find the re-use of Arapahoe 3 as a synchronous condenser plus the installation of 90 MVARs of new shunt capacitors, will together offer a cost effective solution for providing both dynamic and static VAR support at Arapahoe Station.

115. We also find the conversion of Arapahoe 4 from coal-fired generation to natural gas generation to be needed and in the public interest for emission reduction purposes. Although the Commission previously approved early retirement of Arapahoe 4 in Docket No. 07A-447E, its conversion into a natural gas-fired facility will allow the plant to operate during peak loading and other adverse system conditions with no or inexpensive capital investments. Therefore, we find fuel conversion at Arapahoe 4 in 2014 to be the proper implementation of HB 10-1365 for this coal-fired electric generation unit.

116. We recognize that under certain conditions it is less costly and better for the environment to burn gas in higher efficiency natural gas-fired units than using natural gas in coal units such as Arapahoe 4. Alternative replacement capacity solutions in the future, including new or reconfigured transmission resources or IPP-provided generation, may also prove to be relatively more cost effective than fuel conversion under different circumstances, particularly with respect to projected costs for natural gas. We therefore require Public Service to present alternatives to running Arapahoe 4 on natural gas in its ERP filing due October 31, 2011, so long as these potential alternatives meet or exceed the emission reductions achieved by the fuel conversion we adopt here.

4. Valmont 5

117. Valmont 5 is a 187 MW coal-fired electric generation facility that began operations in 1964 and whose expected useful life ends in 2024.

118. Valmont 5 would be retired before the end of 2017 under Public Service's proposed scenario. In the Benchmark 1.0 scenario, SCR controls would be installed on Valmont 5 before the end of 2015 at a cost of approximately \$86.7 million, plus or minus 20 percent. Hrg. Ex. 10, at 12.

119. Although Valmont 5 is not quite as old as the Cherokee 1, 2 and 3, we find early retirement after a few more years of operation as a coal-fired unit to be a cost-effective approach for meeting current and reasonably foreseeable emission reduction requirements. We therefore find the retirement of Valmont 5 in 2017 to be needed and in the public interest for emission reduction purposes.

5. Pawnee

120. Pawnee is a 505 MW coal-fired electric generation facility that began operations in 1981 and whose expected useful life ends in 2041.

121. Under the Company's proposed scenario, both SCR and LSD would be retrofitted on the unit for NO_x and SO₂ emission reductions beginning in 2014. In addition, the unit would receive a sorbent injection system for mercury emissions. These installations would have the most impact on overall emissions from the Company's plan. *Id.* at 14. The capital cost of these projects would be \$236.5 million, plus or minus 20 percent. *Id.* at 15.

122. The CDPHE states that Pawnee must be included in Public Service's plan because it is a Best Available Retrofit Technology (BART) source that must be addressed under EPA's Regional Haze Rule. *See* Tourangeau Answer Testimony (Hrg. Ex. 33), at 6. Public Service

explains that retiring Pawnee for emission reduction purposes would result in approximately \$600 million in increased costs to ratepayers. Public Service SOP, at 27.

123. We agree that emission controls on Pawnee are preferable to early retirement given the relatively young age of the plant and its cost effectiveness as a coal-fired electric generation unit. We further find that including the emission control projects at Pawnee in the Company's plan allows us to consider a coordinated approach for emission reduction as contemplated by HB 10-1365. We therefore approve the installation of SCR, LSD, and sorbent injection controls at Pawnee as needed and in the public interest for emission reduction purposes.

6. Hayden

124. Hayden 1 is a coal-fired electric generation facility that began operations in 1965 and whose expected useful life ends in 2025. Hayden 2 is a coal-fired electric generation facility that began operations in 1976 and whose expected useful life ends in 2036. Public Service is a partial owner of both Hayden 1 and 2 such that the Company obtains 139 MW from Hayden 1 (75.5 percent) and 98 MW from Hayden 2 (37.4 percent).²⁰

125. Hayden 1 and 2 were included in the Company's proposed scenario contingent upon the outcome of the AQCC's regional haze BART determinations for those units. The CDPHE reported that the AQCC made a preliminary final determination on November 19, 2010 that BART for Hayden Station is SCR for NO_x reduction. The AQCC therefore has adopted a BART equivalent emissions rate for the regional haze SIP. *See* Tr. Nov. 20, 2010, at 81.

²⁰ Hayden 1 is owned in partnership with PacifiCorp. Hayden 2 is owned in partnership with PacifiCorp and the Salt River Project.

126. As a result of the AQCC's actions concerning Hayden Station, Public Service requests that the units be included in the Company's plan and for the costs of the SCR controls to be eligible for the recovery under the provisions of § 40-3.2-207, C.R.S., as applicable.

127. Under the Company's proposed scenario, Hayden 1 would receive SCR controls in 2015 at an approximate capital cost to Public Service of \$67.1 million, plus or minus 20 percent. Hrg. Ex. 10 at 13. Hayden 2 would receive SCR controls in 2016 at an approximate capital cost to Public Service of \$80.7 million, plus or minus 20 percent. *Id.* at 14.

128. In light of the AQCC's BART determination, we find that SCR controls on Hayden 1 and 2 are needed and in the public interest for emission reduction purposes. We further find that the including of the emission control projects at Hayden in the Company's plan allows for a coordinated approach for emission reduction to be adopted on a cost-effective basis as contemplated by HB 10-1365. Public Service can therefore avail itself of the cost recovery provisions in § 40-3.2-207, C.R.S., consistent with the discussion below.

7. Cherokee 4

129. Cherokee 4 is a 352 MW coal-fired electric generation facility that began operations in 1968 and whose expected useful life ends in 2028. Cherokee 4 is the largest coal unit in the Denver metro area.

130. Whether Cherokee 4 should be retired and its capacity replaced, whether it should instead be retrofitted with SCR controls, or whether it should be converted from coal to natural gas was the most controversial issue concerning resource selection in this Docket. Under scenario 5B, the plant continues to operate burning coal with SCR controls installed in 2016. The plant is retired and replaced with a 314 MW 1X1 CC at Cherokee Station in scenarios 6.2J

(2017), 7E (2018), and 6E FS (2018). Under scenario IPP2, Cherokee 4 is retired in 2017 and is replaced with a 147 MW CT.

131. Public Service estimates that SCR controls would cost \$174.9 million, plus or minus 20 percent. *See* Hrg. Ex. 10, at 11. Staff argues that these costs can be substantially reduced by the re-sequencing of the various construction projects at Cherokee Station. *See* Staff SOP, at 9.

132. Public Service estimates that a new 1X1 installed at Cherokee Station would cost \$346.5 million, plus or minus 20 percent, if the Company procures a new steam turbine for the facility. *See* Ford Supplemental Direct Testimony (Hrg. Ex. 158), at 3. The Company estimates that a new CT at Cherokee Station would cost \$107.4 million, plus or minus 20 percent. *See* Hrg. Ex. 10, at 28.

133. The STRATEGIST model runs do not clearly demonstrate which of the three alternatives for Cherokee 4 is superior in terms of costs and rate impacts. Operating the unit on coal with SCR would meet reasonable foreseeable emission reduction requirements under the CAA, but this option, as represented under scenario 5B, would nevertheless result in relatively higher levels of NO_x, SO₂, mercury, and CO₂ emissions, as compared to certain other alternatives. Plant retirement and replacement under scenario 6.2J would improve emission reductions relative to scenario 5B, but these emission reductions would be achieved as a result of relatively higher capital spending between 2011 and 2017, but not necessarily higher overall revenue requirements.

134. Converting Cherokee 4 from coal to natural gas in 2017, similar to the proposed conversion of Arapahoe 4, would preserve an additional source of real power at Cherokee Station with little or no additional capital investment. Under a reasonable range of projected natural gas

costs, and given the long-term gas contract offered by Anadarko and the potential for more such contracts in the future, we conclude that fuel switching is the superior option for Cherokee 4. We therefore find that conversion of Cherokee 4 from coal to natural gas before the end of 2017 is needed and in the public interest for emission reduction purposes.

135. As with Arapahoe 4, circumstances may change such that it becomes less expensive and more effective from an emission reduction perspective to no longer burn natural gas at Cherokee 4. New or reconfigured transmission resources, IPP-provided generation, and new alternative proposals for replacement generation at Cherokee Station might become more attractive vis-à-vis fuel conversion under different circumstances in the future. We therefore require Public Service to present alternatives to running Cherokee 4 on natural gas in its ERP filing due October 31, 2011, so long as these potential alternatives meet or exceed the emission reductions achieved by the fuel conversion we adopt here. Along those lines, we encourage Public Service to continue to explore the early retirement of Cherokee 4 such that the unit no longer operates after 2022.

8. Replacement Capacity

136. Section 40-3.2-207(6), C.R.S., states, “the commission shall allow, but not require, the utility to develop and own as utility rate-based property any new electric generating plant constructed primarily to replace any coal-fired electric generating unit retired pursuant to the plan.”

137. Public Service proposes to replace the retired capacity of Cherokee 1, 2, and 3 as well as Valmont 5 (a combined 551 MW of retired capacity) with a new 2X1 CC at Cherokee Station (569 MW). The Company estimates that the cost of the new 2X1 CC would be approximately \$487.5 million, plus or minus 20 percent. *See* Hrg. Ex. 158 at 3.

138. Public Service explains that in addition to providing real power from the Cherokee Station after these coal units are retired, the new 2X1 CC will better position the Company to acquire more intermittent renewable resources in the future. *See* Public Service SOP, at 12.

139. Because we have found the retirement of Cherokee 1, 2, and 3, as well as Valmont 5 as needed and in the public interest for emission reduction purposes, we agree that Public Service should be allowed to build replacement capacity in the form of a new 2X1 CC of approximately 569 MW at Cherokee Station. By locating the new plant at Cherokee Station, Public Service will be able to continue to locally satisfy real power needs in the Denver area. We will therefore grant Public Service a presumption of need for 2X1 CC at Cherokee Station with respect to a future application for a CPCN for that facility.

9. Gas Infrastructure

140. Public Service requests that the Commission recognize that the new gas-fired 2X1 CC units at Cherokee will need adequate gas transportation infrastructure and that a new pipeline will eventually be included in gas rate base with charges to the electric department for service rendered. Public Service SOP, at 29. We agree, and find that our decision in this matter creates an incremental need for gas service at the Cherokee generation plant. Though this Docket does not address the specific gas-department distribution system capacities, needs, or alternative methods of providing such incremental gas service, we agree with Public Service that a 24-inch pipeline extending approximately 32 miles from CIG's Fort Lupton compressor facility to the Cherokee plant can be constructed in the ordinary course of business.

10. Future Filing Requirements

141. In its STRATEGIST modeling, Public Service used the decommissioning and removal costs developed for its last general rate case, Docket No. 09AL-299E. *See* Hrg. Ex. 2, at 142. These costs, developed by the Company's consultants in 2007 and labeled the "TLG Services Study," were proposed for the establishment of base rates but were ultimately not adopted by the Commission by virtue of our approval of a settlement agreement in which Public Service consented to apply removal costs approved in an earlier rate case proceeding.

142. Rule 3103 of the Commission's Rules Regulating Electric Utilities requires an electric utility to file applications for authority from the Commission to amend a CPCN in the event that the utility seeks to "discontinue without equivalent replacement" any facility not in the ordinary course of business. *See* Rule 3103, 4 *Code of Colorado Regulations* (CCR) 723-3.

143. We find that it is necessary under Rule 3103, 4 CCR 723-3, for Public Service to amend its CPCNs for the coal-fired generation units whose retirement we have just approved. The early retirement of generation plants does not constitute the Company's "ordinary course of business." Moreover, we are concerned that the decommissioning and removal costs set forth in the TLG Services Study are too limited and may not have been sufficiently reviewed by the Commission in Docket No. 09AL-299E.

144. Because we have decided in this Docket that the retirement of these plants is necessary and in the public interest, and in order to move ahead with the plant closures in a timely fashion, we will not require Public Service to satisfy all of the usual CPCN filing requirements set forth in Rule 3103, 4 CCR 723-3. A modified application proceeding limited to Commission review and approval of detailed cost estimates and schedules associated with the closure and decommissioning of the Cherokee and Valmont units will instead suffice. We will

therefore waive certain provisions under Rule 3103, 4 CCR 723-3, such that Public Service will be required to provide in the application only the following elements:

- the information required in Commission Rules 3002(b) and 3002(c), consistent with conventional application filings;
- a description of the proposed facilities to be decommissioned and/or removed;
- estimated costs of the decommissioning and/or removal of these facilities; and
- anticipated start date of the decommissioning and/or removal work, a schedule for these activities, and a completion date.

145. Public Service may file an application as described above for each unit to be retired, or the Company may file a single application addressing all of the units to be retired pursuant to this Decision. Such applications shall be submitted three months prior to the commencement of the Company's next electric base rate proceeding.

146. Rule 3102 requires an electric utility to file applications for a CPCN for all new electric generation facilities. *See* Rule 3102, 4 CCR 723-3. Accordingly, Public Service recognizes that it must file an application for a CPCN for the 2X1 CC to be constructed at Cherokee Station. *See* Public Service SOP, at 28-29.

147. Public Service also acknowledges that the cost information for new facilities it provided in this Docket is not CPCN quality. *See* Public Service SOP, at 61. We agree, but we are nonetheless satisfied that the cost information the Company has presented is sufficient for the purpose of approving a plan under HB 10-1365 and determining whether the costs of the plan result in reasonable rate impacts under § 40-3.2-205(1)(g), C.R.S. For actual ratemaking purposes, however, Public Service's cost estimates as presented in this Docket are too high-level and preliminary to be relied upon.

148. We recognize that by this Decision the Commission has already determined a need for the new 2X1 CC at Cherokee Station. Therefore, we will not require Public Service to

submit all of the information typically required under Rule 3102, 4 CCR 723-3, for a new generation facility. Our intent is for the CPCN proceeding to focus narrowly on the Commission review and approval of detailed cost estimates and project schedules associated with the construction of the new generation plant. We thus direct Public Service to file the following elements under Rule 3102; 4 CCR 723-3,

- the information required in Commission Rules 3002(b) and 3002(c), consistent with conventional application filings;
- a description of the proposed facilities to be constructed;
- estimated costs of the proposed facilities to be constructed;
- anticipated construction start date, construction period, and in-service date;
- a map showing the general area or actual location where facilities will be constructed at Cherokee Station; and
- electric one-line diagrams, as applicable.

149. Public Service has also requested that the Commission enter a finding that applications for CPCNs for the emission controls at Pawnee and Hayden not be required. We decline to grant this request because the cost estimates presented in this Docket are not CPCN quality. Moreover, the costs of these projects are substantial, and, as evidenced by HB 10-1365 itself, these projects are not in the Company's ordinary course of business. Accordingly, we also waive Rule 3205(b)(II), 4 CCR 723-3, which concerns pollution control system retrofits.

150. Notwithstanding our concerns about the lack of detailed cost estimates, the Commission has determined that the proposed controls at Pawnee and Hayden are needed and in the public interest by this Decision. Public Service shall therefore file a modified application for a CPCN for the proposed controls, consistent with the discussion above for the application for a CPCN for the proposed 2X1 CC at Cherokee Station.

151. Finally, we expect that the applications for CPCNs required by this Decision will allow us to consider the establishment of a not-to-exceed maximum level of expenditures for

these projects. In conjunction with the cost recovery mechanisms we address later in this Decision, we find that the future application filings outlined above are necessary to ensure that the costs and rate impacts associated with the plan remain reasonable over the course of its implementation.

11. Overview of Emission Reduction Plan, as Modified

152. The Commission has approved by this Decision, an emission reduction plan that entails the early retirement of five coal-fired electric generating units, emission controls for three additional units, and the fuel conversion of two units from coal to natural gas. The emission reduction plan we adopt pursuant to HB 10-1365 is thus summarized in the table below:

Unit	Size	Action	Date
Cherokee 1	107 MW	Retirement	2011
Cherokee 2	106 MW	Retirement	2011
Cherokee 3	152 MW	Retirement	2015
Cherokee 4	352 MW	Conversion	2017
Arapahoe 3	45 MW	Retirement	2013
Arapahoe 4	111 MW	Conversion	2014
Valmont 5	186 MW	Retirement	2017
Hayden 1	139 MW	Controls	2015
Hayden 2	98 MW	Controls	2016
Pawnee	505 MW	Controls	2014

153. Under the approved emission reduction plan, 551 MW of coal-fired electric generation will be retired, 742 MW of coal-fired electric generation will be controlled with emission reducing retrofits, and 463 MW of coal-fired electric generation will be fuel switched from coal to natural gas.

154. The capital costs associated with this coordinated approach to emission reductions, including the costs of a new 2X1 natural gas-fired CC plant (569 MW) at Cherokee

Station to serve as replacement capacity for the retired units, are presently estimated to be approximately \$890 million through 2017, within an error band of plus or minus 20 percent.

155. Consistent with the discussion above concerning the projections of future coal, natural gas, and carbon costs, we believe the potential range of overall rate impacts of this plan and the corresponding range of emission reductions have been properly developed by the Company's STRATEGIST model runs. *See* Hrg. Exs. 189, 251, and 256.

156. Based on these modeled results, we conclude that the modified emission reduction plan established by this Decision can be implemented at a reasonable cost and rate impact. Moreover, we find that the modified plan will result in significantly more emission reductions than the minimums required by HB 10-1365, to benefit the public health.

G. Analysis of the Modified Plan

157. HB 10-1365 sets forth the General Assembly's belief that a coordinated plan of emission reductions from coal-fired power plants will enable Public Service to meet the requirements of the CAA and protect the public health and the environment at a lower cost than a piecemeal approach. § 40-3.2-202(1), C.R.S. In order to accomplish the important objectives of HB 10-1365, we have taken the following statutory factors into consideration in approving this modified version of Public Service's preferred scenario.

1. Satisfaction of the August 15 Filing Deadline

158. Section 40-3.2-204(1), C.R.S., requires the Company to file its emission reduction plan on or before August 15, 2010. Public Service filed its plan on August 13, 2010.

159. A number of parties claim that, because the Commission rejected scenario 6.1E, the entirety of the plan was rejected by Decision No. C10-1067. As a result, these parties claim the alternative scenarios the Company presented in its supplemental direct testimony of

October 25, 2010 must be rejected as untimely filed. *See* Peabody's Motion for Summary Judgment and for Shortened Response Time, filed October 29, 2010; AGNC SOP, at 3-5; CMA SOP, at 3-6; Peabody SOP, at 14-19.

160. The Commission does not agree. Scenario 6.1E was one of many scenarios contained in the Company's August 13, 2010 plan. After we rejected scenario 6.1E, a number of those scenarios remained viable for the Commission's consideration including, for example, scenario 5B. In addition, the scenarios identified in the October 25, 2010 supplemental direct testimony constitute modifications of scenarios originally presented in the August 13, 2010 filing. The Commission has the authority to modify the Company's plan. § 40-3.2-205(2), C.R.S. As a result, the Commission could have modified the plan to create any of the scenarios the Company presented on October 25, 2010, even if the supplemental testimony had not been allowed. The Commission's ability to modify the Company's plan would be rendered meaningless if we were limited to adopting only those scenarios set forth in the Company's August 13, 2010 filing. *See* Decision No. C10-1265 at ¶¶ 21-25.

161. We therefore find the Company satisfied the August 15, 2010 filing deadline.

2. Scope of the Plan

162. Section 40-3.2-204(2)(a), C.R.S., requires that the emission reduction plan address "a minimum of nine hundred megawatts of fifty percent of the utility's coal-fired electric generating units in Colorado, whichever is smaller." In evaluating compliance with this requirement, the calculation "shall not include any coal-fired capacity that the utility has already announced it has plans to retire, prior to January 1, 2015." *Id.*

163. Public Service's emission reduction plan addresses 1,801 MW of its coal-fired electric generation in Colorado. Excluding the MW associated with Arapahoe 3 and 4, both of

which were slated to be retired, the plan addresses 1,645 MW. Therefore, the Commission finds the plan satisfies this requirement.

3. CDPHE Determination Regarding Consistency with Reasonably Foreseeable Emission Reduction Requirements

164. Section 40-3.2-204(2)(b)(IV), C.R.S., states, “the Commission shall not approve a plan . . . unless the Department has determined that the plan is consistent with the current and reasonably foreseeable requirements of the federal [Clean Air] act.” The Commission has interpreted HB 10-1365 as recognizing the CDPHE is the state agency with the authority and expertise to determine what requirements of the federal CAA are reasonably foreseeable. *See* Decision Nos. C10-1067 and C10-1164. Therefore, the Commission has generally deferred to the CDPHE in matters pertaining to determining which emission reduction requirements are reasonably foreseeable, as well as how far into the future such requirements can reasonably be foreseen. In other words, while the Commission is permitted to opine on the costs associated with reasonably foreseeable emissions reduction requirements, HB 10-1365 does not permit the Commission to assess what those requirements will be, as a general matter.

165. The CDPHE determined scenario 6E FS, which, from an air quality standpoint, closely resembles the plan we approve today, is consistent with reasonably foreseeable requirements of the CAA. CDPHE SOP, at 12. *See also* Hrg. Ex. 200, at 4.

4. Full Implementation by 2017

166. Section 40-3.2-204(2)(c), C.R.S., requires that the plan “include a schedule that would result in full implementation of the plan on or before December 31, 2017.” Further, this schedule must be designed “to protect system reliability, control overall cost, and assure consistency with the requirements of the [CAA].” *Id.* Each element of the plan we approve

today that is necessary to satisfy reasonably foreseeable emissions reduction requirements is scheduled to occur on or before December 31, 2017. Therefore, we find the implementation deadline is satisfied.

5. Identification of Associated Costs

167. Section 40-3.2-204(2)(d), C.R.S., states “[t]he plan shall set forth the costs associated with the activities identified in the plan,” including “planning, development, construction, and operation of elements.” Public Service did provide estimates of planning, development, construction, operation, shutdown, decommissioning, and repowering costs for each of its scenarios. Though we will order additional review of these costs through the application procedures described above, we find they are sufficient to satisfy the requirements of HB 10-1365.

6. Relative Cost Differences

168. Section 40-3.2-206(3)(a), C.R.S., requires us to “compare the relative costs of repowering or replacing coal facilities with natural gas generation or other low-emitting resources, including energy efficiency, to an alternative that incorporates emission controls on the existing coal-fired units.” Public Service did present an all-controls alternative, known as Benchmark 1.0. Based on our review of the STRATEGIST model results for the various scenarios, we believe the plan we approve today comes at a lower cost to ratepayers than an all-controls option. *See* Hrg. Ex. 251. Therefore, we believe this factor weighs in support of the approved plan.

7. CDPHE Report Concerning Reduction in Emissions of Oxides of Nitrogen

169. The Commission must consider whether the CDPHE “reports that the plan is likely to achieve at least a seventy to eighty percent reduction, or greater, in annual emissions of oxides of nitrogen.” § 40-3.2-205(1)(a), C.R.S. In making this determination, the CDPHE is required to consider “emissions from coal-fired power plants identified in the plan and continuing to operate after retrofit with emission control equipment,” as well as “emissions from any facilities constructed to replace any retired coal-fired power plants identified in the plan.” *Id.*

170. The CDPHE determined scenario 6E FS, which has an emissions profile very similar to the plan we approve today, meets and exceeds the minimum standard for NO_x reduction. CDPHE witness Mr. Tourangeau testified that the plan we approve here today will reduce NO_x from 18,147 tpy to 3,095 tpy, which constitutes an 83 percent reduction. Hrg. Ex. 200, at 2. These emission reductions will be further improved if Public Service opts to run Cherokee 4 at a lower capacity. For example, if the Company operates Cherokee 4 on natural gas at a 50 percent capacity factor, as it represented to the CDPHE it would, NO_x emissions would be further reduced to 2,434 tpy, for an overall reduction of 87 percent. *Id.* at 3.

171. Because the plan we approve today is predicted to reduce NO_x emissions by more than 80 percent, we believe this factor supports the approved plan.

8. CDPHE Determination Pursuant to § 40-3.2-204(2)(b)(III), C.R.S.

172. Section 40-3.2-204(2)(b)(III), C.R.S, requires the CDPHE to “determine whether any new or repowered electric generating unit proposed under the plan, other than a peaking facility utilized less than twenty percent on an annual basis or a facility that captures and sequesters more than seventy percent of emissions not subject to a national ambient air quality

standard or a hazardous air pollutant standard, will achieve emission rates equivalent to or less than a combined-cycle natural gas generating unit.”

173. Section 40-3.2-205(1)(b), C.R.S., requires us to consider whether the CDPHE made this determination. The new gas-fired replacement unit we approve as part of the plan is a CC natural gas generating unit. Therefore, this section is inapplicable to the new replacement generation. However, we note that the CDPHE does not seem to have made a specific finding as to the repowered units, Arapahoe 4 and Cherokee 4, which will be converted to run on natural gas. Nonetheless, this is only one factor among many the Commission must consider. Given that the CDPHE has determined the plan we approve today is consistent with current and reasonably foreseeable emissions reduction requirements, we believe the plan satisfies the air quality goals embodied in HB 10-1365.

9. The Degree to Which the Plan Will Result in Reductions in Other Air Pollutant Emissions

174. Section 40-3.2-205(1)(c), C.R.S., requires us to consider “the degree to which the plan will result in reductions in other air pollutant emissions.” In addition to achieving significant reductions in NO_x emissions, the plan we approve today will also reduce emissions of SO₂, particulate matter, greenhouse gasses, and mercury. *See* Hrg. Ex. 200, at 2-3. We believe the approved plan meets and exceeds the air quality improvements that motivated the legislature to pass HB 10-1365. As a result, we believe this factor weighs in favor of approving the plan.

10. The Degree to Which the Plan Will Increase Utilization of Existing Natural Gas-Fired Generating Capacity

175. Section 40-3.2-205(1)(d), C.R.S., requires us to consider “the degree to which the plan will increase utilization of existing natural gas-fired generating capacity.” *See also* § 40-3.2-206(3)(d), C.R.S. The STRATEGIST model runs prepared by the Company present

increased gas burn from existing facilities for all proposed scenarios. For scenario 6E FS, which closely resembles the plan we have approved, increased usage of existing natural gas units was clearly demonstrated. *See* Hrg. Exs. 188 and 189. We believe the approved plan significantly increases the utilization of existing facilities that are capable of running on natural gas. Therefore, we believe this factor weighs in favor of the approved plan.

11. Satisfaction of Clean Energy Requirements, and Utilization of Energy Efficiency or Other Low-Emitting Resources

176. Section 40-3.2-205(1)(e), C.R.S., requires us to consider “the degree to which the plan enhances the ability of the utility to meet state or federal clean energy requirements, relies on energy efficiency, or relies on other low-emitting resources.” The CDPHE has stated the emissions profile of the plan we approve today will satisfy reasonably foreseeable emission reduction requirements and, as a result, the Commission believes it is likely to help the Company meet clean energy requirements. Further, we find the plan does rely on resources that are lower emitting than existing coal-fired plants, such as natural gas-fired facilities. We therefore find this factor supports approval of the plan.

12. Promotion of Colorado Economic Development

177. Section 40-3.2-205(1)(f), C.R.S., requires us to consider “whether the plan promotes Colorado economic development.” Public Service’s economic impact analyses suggest that the plan we adopt will positively impact Colorado’s economy. *See* Sheesley Supplemental Direct Testimony (Hrg. Ex. 159). Similarly, Anadarko testified that more gas generation in Colorado would support more gas-industry jobs in the state. *See* Anadarko SOP, at 37. Additionally, the plan we approve here today will most certainly create new construction jobs as the Company’s facilities are replaced or retrofitted. By contrast, the evidence on impacts to the Colorado coal industry is somewhat ambiguous. Much of the impact depends on whether

Peabody and other coal-producing companies will open new mines to replace the mines that are going to close in the near term, such as the Twentymile Mine.

178. On balance, the Commission is convinced that the overall economic impact of the plan we approve here today will be positive. While predicting the movement of the economy is always inexact, we believe adopting this coordinated approach to achieving emissions reductions will put Colorado at a competitive advantage with regard to utility rates in the near future. As such, we find this factor supports approving the plan.

13. Preservation of Reliable Electric Service

179. Section 40-3.2-205(1)(g), C.R.S., requires us to consider whether the plan preserves reliable electric service for Colorado customers. Public Service has consistently stated that system reliability is dependent on maintaining two sources of real power and three sources of reactive power support at the Cherokee site. *See* Mogensen Direct Testimony (Hrg. Ex. 6), at 12. We find the approved plan meets this requirement. The new 2x1 CC facility and the fuel switched Cherokee 4 will serve as two sources of real power. These same facilities, together with Cherokee unit 2 converted to a synchronous condenser, will also serve as three sources of reactive power support. Further, the approved retirement dates of the existing coal-fired units leave adequate time for conversion of Cherokee unit 2 and the construction of the 2x1 CC unit to ensure that three sources of generation are available during the implementation of the plan.

180. Further, while testimony on reliability was mainly focused at the Cherokee site, there are obvious requirements for reactive power support at Arapahoe. To address this need, Public Service recommended and we approved, the conversion of Arapahoe 3 to a synchronous condenser by 2014.

181. We find the foregoing is sufficient to preserve reliable electric service for Colorado customers. As such, we believe this factor supports approval of the plan.

14. Protection from Future Cost Increases

182. Section 40-3.2-205(1)(h), C.R.S., requires us to consider “whether the plan is likely to help protect Colorado customers from future cost increases, including costs associated with reasonably foreseeable emission reduction requirements.” As stated above, the Commission agrees with the General Assembly’s finding that the coordinated approach we approve today will, in the long term, be less costly to consumers than a piecemeal approach to compliance with the CAA and other reasonably foreseeable emissions reduction requirements. As a result, we find this factor weighs in favor of approving the plan.

15. Reasonable Rate Impacts

183. Section 40-3.2-205(1)(i), C.R.S., requires us to consider “whether the cost of the plan results in reasonable rate impacts.” In making this determination, we are directed to “examine the impact of the rates on low-income customers.” *Id.* We find the projected percentage change in customers’ bills that will result from implementation of the plan is reasonable, particularly when the plan’s health benefits and air quality improvements are considered. Further, we find this coordinated approach will ultimately provide a benefit to all customers, including the low-income. As a result, we find this factor supports approval of the plan.

184. Related to this consideration, the Gas Intervenors suggest implementation of a surcharge on the plan-related costs recovered from ratepayers, the funds from which would be transferred to Colorado’s Low Income Energy Assistance Program, known as LEAP. Gas Intervenors SOP, at 65. The Commission finds the Gas Intervenors’ suggestion, which was

raised in its SOP, is not sufficiently developed to warrant adoption in this Order. However, the Commission is currently exploring a potential rulemaking on low-income energy assistance programs. *See* Docket Nos. 10M-473E and 10M-475G. The Commission encourages all interested intervenors in this Docket to participate in those Miscellaneous Dockets if they wish to further address rate impacts on low-income customers.

16. Conclusions Regarding the Modified Plan

185. The plan we approve today satisfies the minimum requirements related to timeliness, § 40-3.2-204(1), C.R.S.; scope, § 40-3.2-204(2)(a), C.R.S.; CDPHE approval, § 40-3.2-204(2)(b)(IV), C.R.S.; scheduled implementation, § 40-3.2-204(2)(c), C.R.S.; and identification of costs, § 40-3.2-204(2)(d), C.R.S. Further, we find the nine factors set forth at § 40-3.2-205(1), C.R.S., when considered as a whole, support our approval of the plan, as modified.

H. Cost Recovery

1. Cost Recovery Provisions of HB 10-1365

186. HB 10-1365's introductory legislative declaration contains the following:

The General Assembly further finds and declares that Colorado rate-regulated utilities require timely and forward-looking reviews of their costs of providing utility service in order to undertake the comprehensive and extensive planning and changes to their business operations contemplated by [HB 10-1365]. . . . To that end, the General Assembly finds that the commission should have additional tools and more flexibility in its regulatory authority to ensure the continued financial health of these utilities.

§ 40-3.2-202(3), C.R.S. The substantive cost recovery provisions of HB 10-1365 are then set forth in §§ 40-3.2-205(3), C.R.S. and 40-3.2-207, C.R.S., *et seq.* Section 40-3.2-205(3), C.R.S., is contained in the "Review – Approval" section of HB 10-1365 and provides that "[a]ll actions

taken by the utility in furtherance of, and in compliance with, an approved plan are presumed to be prudent actions, the costs of which are recoverable in rates as provided in section 40-3.2-207.”

187. Section 40-3.2-207, C.R.S., commences with its own legislative declaration. This legislative declaration echoes § 40-3.2-205(3), C.R.S., and states that Public Service is “entitled to fully recover the costs that it prudently incurs in executing an approved emission reduction plan.” § 40-3.2-207(1)(a), C.R.S. Subsection 207(1)(a), C.R.S., goes on to broadly define costs as activities in the “planning, developing, constructing, operating, and maintaining” any emission control or replacement capacity constructed pursuant to the plan. The second half of the legislative declaration acknowledges that the activities Public Service will undergo pursuant to its approved emission reduction plan will be conducted “outside of the normal resource planning process.” § 40-3.2-207(1)(b), C.R.S. Section 40-3.2-207, C.R.S., then sets forth four provisions addressing various aspects of cost recovery.

188. Section 40-3.2-207(2), C.R.S., permits the Commission to assign a portion of the cost of the emission reduction plan to Public Service’s wholesale customers and expects Public Service to pursue a good faith application with the Federal Energy Regulatory Commission (FERC) for recovery of these dollars from its wholesale customers. Section 40-3.2-207(2), C.R.S., contains a “make-whole” provision in the event the FERC does not permit recovery of the entire plan-related rate increase Public Service requests.

189. Section 40-3.2-207(3), C.R.S., permits “current recovery” of “construction work in progress at the utility’s weighted average cost of capital, including its most recently authorized rate or return on equity, for expenditures on projects associated with the plan during the construction, startup, and pre-service implementation phases of the projects.”

190. Section 40-3.2-207(4), C.R.S., states the Commission shall employ rate-making mechanisms that allow for adjustments not less than once per year, without requiring Public Service to file a general rate case, “to the extent that” Public Service can show: (1) the “approved plan includes the early conversion or closure of coal-based generation capacity by January 1, 2015;” and (2) the plan contributes to “a lag in the recovery of the costs of the plan related to the investment required,” which contributes to Public Service “earning less than its authorized return on equity.” This paragraph contains no requirement that the special regulatory mechanism be implemented on a forward looking basis versus a historical basis; however, the Commission’s review of the costs to be recovered through the special rate-making mechanism may not amount to a full blown rate case.

191. Finally, § 40-3.2-207(5), C.R.S., provides that “during the time any special regulatory practice is in effect, the utility shall file a new rate case at least every two years or file a base rate recovery plan that spans more than one year.”

2. Public Service’s Request Concerning Cost Recovery and the Opposition Thereto

192. Public Service took the position from the very outset of this proceeding that a fully-projected cost recovery approach would be required to carry out the requirements of HB 10-1365. To this end, Public Service proposed to recover both its CWIP and its accelerated depreciation and removal costs through an automatic adjustment clause, which it proposed go into effect on January 1, 2011. This rider would be known as the ERA and would have a true-up mechanism. The ERA would not be used to recover the costs of plan-related assets once they are placed in service. Public Service included an illustrative advice letter with its August 13, 2010 filing. However, during the course of the proceedings it became apparent that Public Service could not finalize this advice letter until after December 15, 2010 when it knew the

Commission's rulings on both resource selection and the permissibility of the implementation of the ERA. During the first round of hearings, Public Service stated the 2011 ERA would be in the range of \$14.1 million; however, this amount was later corrected in the second round of hearings to the range of \$16.8 million.²¹

193. Public Service contends that ratepayers will best benefit from an approach to cost recovery that spreads out the rate increases over the greatest number of months. For this reason, Public Service proposed a rider that collects projected cost and expenses from ratepayers in advance of the actual date in which some of those costs would in fact be incurred. Public Service takes the position that an automatic adjustment clause based on projected pre-CPCN approval CWIP expenditures is required by HB 10-1365 and that it met both of the "to the extent" triggers contained in § 40-3.2-207(4), C.R.S., such that it may use the ERA also to recover its accelerated depreciation and removal costs.²²

194. Public Service requests the Commission approve the ERA and associated tariff sheets to allow current return on capitalized CWIP at the Company's weighted average cost of capital including its most recently authorized rate of return on equity²³ and to allow, using a two- or four-year amortization period, recovery of incremental 2011 plant related costs (accelerated

²¹ The 19 percent increase must be put into perspective as the estimates associated with the ERA's two components moved in opposite directions. The projected CWIP portion of the ERA decreased by 77 percent (from \$4.7 million to \$1.1 million) and the projected accelerated depreciation and removal cost portion increased by 67 percent (from \$9.4 million to \$15.7 million).

²² Public Service contends that the first trigger – early action – is met for the entire emission reduction plan because Cherokee 1 and 2 are retired before January 1, 2015. As to the second trigger, Public Service contends the accelerated depreciation associated with early retirement of its plants will clearly contribute to earning less than authorized. Public Service argues: "[t]he Company cannot accelerate plant lives by several years and invest a billion in new plant without such a plan contributing to underearnings. . . . Public Service has adequately demonstrated that the plan costs, including accelerated depreciation, will contribute to under earnings." Public Service SOP, at 85.

²³ Public Service contends that § 40-3.2-207(3), C.R.S., is intended to address the expenditures associated with incremental investments – such as scrubbers, catalytic converters, and plant conversions prior to the rate base inclusion date.

depreciation and removal expenses offset by reduced rate base during 2011) associated with the shortened useful lives of any coal plant whose early retirement is within the scope of the approved emission reduction plan.²⁴ Alternatively, in its November 15, 2010 supplemental rebuttal testimony, Public Service proposed deferred accounting for the accelerated depreciation and removal costs as follows:

- i. Public Service shall create and/or adjust a regulatory asset or liability for each plant by an amount equal to the difference between:
 1. The level of depreciation expenses using the removal cost and depreciation currently recovered through base rates for each retired plant; and
 2. The level of depreciation and removal costs estimated to be recognized by the Company in accordance with Generally Accepted Accounting Principles (“GAAP”); and
- ii. Public Service shall recover a return of and a return on such regulatory asset or refund of any regulatory liability balance through base rates in the next general rate case.

Public Service SOP, at 31. Public Service argues these special regulatory approvals are necessary for it to timely execute the approved emission reduction plan and its associated expenditure of approximately \$1 billion dollars over the next seven years. Similarly, Public Service argues that financial harm justifying a special regulatory mechanism is both inevitable and has been proven not only for 2011, but for the term of any approved emission reduction plan. *See* Public Service SOP, at 85.

195. Finally, Public Service seeks a finding that the appropriate share of the costs of the FERC-approved emission reduction plan to be assigned to its wholesale customers is the jurisdictional allocator as it changes over time, so long as the allocator does not conflict with the

²⁴ These plants include Cherokee 1, significant portions of Cherokee 2, Cherokee 3, and Valmont 5.

Company's wholesale contracts that were executed prior to the effective date of HB 10-1365. *See* Public Service SOP, at 32.

196. Several intervenors took issue with Public Service's proposed ERA. At a policy level, these intervenors disagreed that the statutory triggers in § 40-3.2-207(4), C.R.S., had been met. For example, Staff pointed out that Public Service's approach is nothing more than a demonstration that a lag in recovery of the investment costs will reduce "revenues" and therefore does not meet the requirement of HB 10-1365 because the Company's demonstration must be with respect to earnings. *See* Staff SOP, at 14. Intervenors also argued that the demonstration of underearnings needed to justify the use of a special regulatory mechanism should not include the effect of accelerated depreciation and removal costs. They argue that the demonstration should be made more than once during the duration of the approved emission reduction plan, contrary to what is requested by Public Service. Further, several parties took the position that Public Service needed to make more of a demonstration of the contribution to earning less than the authorized return on equity and suggested reliance upon some type of modified Appendix A or monthly surveillance reports. Several intervenors also argued that the recovery of costs under § 40-3.2-207(4), C.R.S., should only be allowed to the level of what would make Public Service "whole" from an earnings perspective, and not guarantee Public Service cost recovery of all costs without regard to the level of underearnings. The general effect of these arguments is that Public Service needs to make a more robust demonstration of underearnings prior to taking advantage of the special regulatory treatment outlined at § 40-3.2-207(4), C.R.S.

197. At the mechanical level, the intervenors addressed such topics as the timing of recovery of a return on CWIP in relation to the timing of an award of a CPCN for a project eligible for current recovery of a return on CWIP, the inclusion of "project development costs" in

the CWIP calculation, the number of months to be used in the calculation of an average CWIP balance, whether to recognize short term debt in the capital structure used to calculate the weighted average cost of capital applied to CWIP, the appropriate use of projected versus historical figures, the confidence with the proposed early retirement date, the proper amortization period for various categories of costs, the levelizing of the revenue requirement, the details of any true-up feature, and clarifications to the proposed tariff text.

198. As noted by the OCC, the cost recovery provisions of HB 10-1365 do not require the Commission to approve a cost recovery plan in this docket on or before December 15, 2010. OCC SOP, at 14. The OCC argues that the Commission defer all cost recovery issues to a future application proceeding in which the guidelines and documents required can be vetted. *Id.* at 15. However, because Public Service will take actions in 2011 pursuant to the plan we are adopting here, we find it is efficient and advisable to make as many determinations as possible based on the evidentiary record that has been developed. The OCC and other interested persons will likely have additional opportunities to opine on the cost recovery issues implicated by HB 10-1365 and the plan we are adopting here.

3. Decision on Wholesale Rates

199. Taken together, the provisions at § 40-3.2-207(2), C.R.S., recognize that Public Service provides both retail and wholesale services. This section then sets forth the basis by which an appropriate proportion of the costs of the approved emission reduction plan can be assigned to Public Service's wholesale customers via a rate proceeding at the FERC. Such a FERC rate proceeding must be commenced within six months of the Commission's final order assigning costs to the wholesale jurisdiction and must be pursued in good faith. HB 10-1365, however, further allows Public Service to recover all costs of the approved Plan from the retail

customers in the event that the FERC disapproves of all or a portion of the wholesale's sectors responsibility for HB 10-1365 costs. Public Service recognizes all of its responsibilities under Subsection 207(2) and, for our purposes in this proceeding, has satisfied all of its obligations.

200. Public Service's request on this issue was unopposed. Public Service is entitled to the finding it seeks on this issue.

201. Specifically, we find when seeking cost recovery from wholesale customers for their appropriate share of the costs of the approved emission reduction plan, Public Service shall use the jurisdictional allocator as it changes over time, so long as the allocator does not conflict with Public Service's wholesale contracts that were executed prior to the effective date of HB 10-1365.

4. Decision on Cost Recovery Related to Construction Work in Progress

202. Public Service seeks an automatic cost adjustment in its proposed ERA. However, Public Service concedes that the dollar amounts it presented as the basis for such a mechanism have not been through the rigors associated with an application for a CPCN. *See* Public Service SOP, at 61. Because we have found that all significant capital investments associated with the approved emission reduction plan require a CPCN, we find that cost recovery of CWIP earnings should not begin until CPCNs for these projects have been issued.

203. Moreover, we disagree with Public Service that § 40-3.2-207(3), C.R.S., requires us to construe "current recovery" as eliminating rate proceedings as the vehicle by which investment in a new plant under construction is included in rate base.

204. Thus, for all investments on projects associated with the approved emission reduction plan (including the non-plant specific "project development costs" identified by Public Service witness Mr. Brockett), Public Service is authorized to recover a return on rate base on a

CWIP amount prior to a plant coming into service. Public Service shall do this by accumulating Allowance for Funds Used During Construction (AFUDC) and requesting the actual recovery of CWIP in a general rate case along with the AFUDC that has accumulated.²⁵ The result is that there will be no AFUDC offset.²⁶ As explained below, this conclusion does not preclude the use of a special regulatory mechanism, such as an automatic adjustment clause, in the event the triggers of § 40-3.2-207(4), C.R.S., are met.

205. We further find that expenditures eligible for current earnings on CWIP must occur between the date of this Commission's decision and December 31, 2017. No party has opposed this position as a general matter.

5. Decision on Cost Recovery Related to Accelerated Depreciation and Removal Costs

206. The Commission recognizes that this Order approving the early retirement of coal-fired electricity generation plants will have immediate consequences for Public Service under generally accepted accounting principles and may negatively impacting the Company's potential to earn its authorized level of return on equity. As explained by Public Service, these immediate consequences can be isolated.

207. We accept Public Service's approach to using deferred accounting, as set forth above, to protect the Company against the possible financial harm associated with the early retirements of Cherokee 1, 2, and 3, as well as Valmont 5. By approving the use of deferred

²⁵ Based on our prior ruling that the Hayden 1 and Hayden 2 SCR investments are within the scope of the approved emission reduction plan, these projects are eligible for the CWIP cost recovery treatment we have approved.

²⁶ Commissioner Matt Baker would have accepted an approach to the current recovery on CWIP that looked more like the Transmission Cost Adjustment rider, so long as the project received CPCN-like approval. Commissioner Baker prefers this result for policy reasons, including its likely positive impact of demonstrating the feasibility of accounting and forecasting concepts that Public Service would use when setting rates based on a future test year.

accounting, we avoid a future claim of retroactive ratemaking if these costs are included in a different test year that may be used in a future rate proceeding.

6. Decision on Special Rate Making Mechanism

208. Public Service is seeking at this time approval only of a mechanism to recover its current return on CWIP as well as accelerated depreciation and removal costs. *See* Brockett Direct Testimony (Hrg. Ex. 23), at 3. Public Service describes this as a modest approach that does not seek to recover all of the costs that Public Service will incur to implement the plan. *See* Tr. Oct. 22, 2010, at 53. Specifically, it does not include recovery of operations and maintenance costs, depreciation expense, insurance, taxes, etc., of new plants as they are brought into service. That being said, Public Service projects the 2011 level of costs (including current earnings on CWIP and accelerated depreciation and removal costs) that will flow through its proposed cost recovery mechanism will be greater than \$30 million. *See* Brockett Supplemental Rebuttal Testimony (Hrg. Ex. 196), at 7.

209. Public Service has not convinced us that its 2011 expenditures on construction projects are so large as to require the adoption of an automatic adjustment mechanism at this time, especially in view of our approval of the Company's proposed deferred accounting for the accelerated depreciation and removal costs. Public Service's proposed tariff language was not thoroughly vetted in the case, and we believe that current recovery of earnings on CWIP can be accomplished in accordance with the Clean Air – Clean Jobs Act without resorting to an automatic adjustment mechanism.

210. Thus, we adopt deferred treatment accounting as the default approach for the CWIP dollars and the accelerated depreciation and removal costs for the duration of the approved emission reduction plan. If Public Service desires different cost recovery, it shall

commence a cost recovery proceeding at the Commission and can prevail only if it meets the two triggers set forth at § 40-3.2-207(4), C.R.S. Prior to commencing a proceeding to implement a different approach to cost recovery than that authorized here, Public Service shall obtain a final Commission order setting forth the theoretical parameters for the alternative approach. Such Commission order will determine the filing requirements and the standard required for Public Service to show how the early action and the lag in recovery contributing to earning less than the authorized return on equity.

211. It is clear from the controversy that Public Service's proposed ERA has attracted that processing and adopting a special regulatory mechanism will likely be contentious and time consuming. In preparing to make its filing to establish a rider or deferred accounting mechanism, Public Service should carefully review the procedural and technical criticisms of its illustrative advice letter and consider making changes to address the critiques. In that way, we hope that efficiencies will be gained in any future proceeding to establish an actual rate rider or deferred accounting procedure.

212. Examples of parameters that Public Service should consider including are whether rate changes can be designed so that they flow directly to base rates without the need for a separate rider and whether the mechanism should be designed so as to bring Public Service back up to only its authorized return on equity. As to this second parameter, it will be necessary to determine how to measure the requisite under-earnings without undertaking a full rate case.

7. Decision on Biennial Rate Cases and Multi-Year Rate Plans

213. Public Service has not put forth its proposed approach as to the form of rate cases and/or rate plans it desires. Rather, Public Service has offered to conduct discussions with interested stakeholders in 2011 to discuss the pros and cons of using multiyear rate plans rather

than riders and rate cases every two years. *See* Hyde Direct Testimony (Hrg. Ex. 1), at 56. We find Public Service's approach to use discussions with stakeholders to address this issue to be reasonable and we shall adopt it.

214. Additionally, we note, that, regardless of the approach taken by Public Service, the requirement from our order in Docket No. 10A-327E that the Company file a rate case no later than April 30, 2012) will meet the two-year requirement of § 40-3.2-207(5), C.R.S.

I. Long Term Gas Contract

215. Section 40-3.2-206(4), C.R.S., states the utility may enter into long-term gas supply agreements to implement the requirements of HB 10-1365. It goes on to state,

A long-term gas supply agreement is an agreement with a term of not less than three years or more than twenty years. All long-term gas supply agreements may be filed with the Commission for review and approval. The Commission shall determine whether the utility acted prudently by entering into the specific agreement, whether the proposed agreement appears to be beneficial to consumers, and whether the agreement is in the public interest. If an agreement is approved, the utility is entitled to recover through rates the costs it incurs under the approved agreement, and any approved amendments to the agreement, notwithstanding any change in the market price of natural gas during the term of the agreement. The Commission shall not reverse its approval of the long-term gas agreement even if the agreement price is higher than a future market price of natural gas.

Id.

216. As a part of its August 13, 2010 proposed plan filing, Public Service requested approval of a long-term gas supply contract with Anadarko (Anadarko Contract).

217. By Decision Nos. C10-0957 and C10-0976, the Commission granted extraordinary protection of the contract and certain testimony, limiting full access to the Anadarko Contract to Staff and the OCC. Because of this confidentiality limitation, the

Commission directed Staff and the OCC to analyze the contract. Although Peabody did not have access to the Anadarko Contract, it nonetheless provides a detailed discussion about potential concerns with long-term contracting, generally, as well as an analysis and recommendations based on the information it reviewed. *See* Montgomery Answer, Cross-Answer, Supplemental Answer, and Supplemental Cross-Answer Testimony (Hrg. Exs. 44, 45, 220, 221, 222, 223, and 224).

1. The Anadarko Contract

218. Public Service implemented an RFP process for long-term gas contracts to complement the Company's proposed emissions reduction plan. Public Service solicited bids for either five- or ten-year terms with pricing that was: (a) fixed for the entire term; (b) collared with a price floor and ceiling; and/or (c) a fixed price with an annual adjustment or escalation. The RFP required the gas to be produced in Colorado, in order to maximize positive impacts on the Colorado economy, consistent with HB 10-1365.

219. Without divulging the confidential terms of the winning Anadarko Contract, Public Service states that it falls within the bidding category which contains "a fixed price offer with an annual adjustment or escalation." The contract is for a ten-year term, with the Cheyenne Hub specified as the delivery point.

220. To assist the Commission and parties in evaluating the Anadarko Contract, Public Service provides a public estimate of the average nominal cost of the associated gas supply of \$5.48 per Dth over the ten years. *See* Hrg. Ex. 2 at 141. Public Service states that if an annual forecast cost of the Anadarko Contract volumes are applied to the STRATEGIST modeling, the Anadarko Contract could result in approximately \$100 million savings in present value revenue requirements. *See* Public Service SOP, at 72.

221. Public Service asserts that the Anadarko Contract is prudent, as it was selected as the winning bidder through a robust competitive bidding process in which all potential bidders were pre-screened from a credit standpoint, and additional credit support or collateral requirements in the form of a corporate parental guaranty were required. The Company also requests a finding that under contract defaults, replacement gas costs would be recoverable through the fuel clause, assuming prudent contract management. *See* Public Service SOP, at 73.

222. In answer testimony, Staff provides a thorough discussion of the Anadarko Contract and addresses the various risks and benefits associated with the specific terms contained in the contract. Staff generally states that the contract is beneficial to customers and in the public interest. Despite the lack of production guarantee behind the gas supply, Staff states that Public Service has received a level of security and credit support from Anadarko's parent companies. Staff raises the notion that although the Anadarko Contract price has escalators and is not a purely a fixed price contract, it does provide a price that will likely be more stable than traditional index-based contracts. Further, the value of reducing volatility should be considered, which may be different from least cost. *See* Kwan Answer Testimony (Hrg. Ex. 41).

223. Staff further asserts it is premature to address a default situation that provides Public Service assurances that it will not be held responsible for any difference between the contract price of the gas and the ultimate replacement cost of such gas. According to Staff, the prudence of Public Service's action, or lack of action, would be determined at the time when a default happens. *See* Staff SOP, at 13.

224. The OCC states the Company conducted a well structured bid solicitation and evaluation process. The selected winning bid is expected to result in lower prices for the natural

gas than would result if the natural gas was purchased at the price forecast filed in this docket. The winning bid also provides some level of customer protection from the price volatility that would likely result from purchasing the natural gas at index prices. In the event of a contract default, the OCC suggests that the Commission should, at that time, evaluate whether the actions that the Company took over time have been prudent and that it has done everything possible to protect the ratepayers and the value of the long-term contract. Accordingly to the OCC, it is premature at this time to simply assume that the implementation of the contract terms will be prudent. *See* Senger Supplemental Answer Testimony (Hrg. Ex. 126).

2. Decisions on Anadarko Contract

225. HB 10-1365 provides that the Commission may approve the contract if it is prudent, of benefit to customers, and in the public interest. As discussed further in Highly Confidential Attachment A, the Commission finds the Company acted prudently in entering into the Anadarko Contract and that it will provide a benefit to consumers, because it will likely provide a lower cost of gas than conventional index-based pricing and greater price stability.²⁷ For these cost-benefit reasons, we similarly find approval of the Anadarko Contract is in the public interest.

226. Peabody recommends that the Commission require Anadarko to provide additional credit to cover the full amount that the Anadarko Contract could be under or over. Public Service asserts that such a requirement would increase the costs of the Anadarko Contract and that existing provisions in the agreement provide adequate protection. *See* Carter

²⁷ The Anadarko Contract is highly confidential, and party review was significantly limited. The confidential attachment to this Decision addresses and makes findings regarding: contract structure; gas produced in Colorado; contrast with current contracting practices; fixed-price aspects of the contract; contract price mechanism; production resource adequacy; transportation capacity; difference between projected contract price and base price forecast; risk of non-performance; and dispute resolution.

Supplemental Rebuttal Testimony (Hrg. Ex. 191), at 2. As discussed in Highly Confidential Attachment A, the terms of the contract lead the Commission to believe Anadarko will be able to meet its obligations. We accept Public Service's assertion that no appreciable benefit would be achieved by requiring additional credit requirements.

227. Peabody also recommends the Commission require an independent evaluator to oversee the management of the Anadarko Contract, if approved. Public Service argues that such a requirement would increase costs and that the Company regularly manages many gas contracts without the benefit of an independent evaluator. *See* Hrg. Ex. 191, at 3. We agree with Public Service that it is not necessary for an Independent Evaluator to oversee the Anadarko Contract, as such a requirement adds significant additional costs and is not warranted in this situation.

228. HB 10-1365 generally intends to provide assurance to the supplier that future Commissions will not prevent the utility from paying costs under the contract and receiving reimbursement from ratepayers for such costs, even if costs are higher than market. Similarly, we believe the utility should be protected from exposure to liability from non-performance of the contract, so long as the Company does not cause the contract breach and any replacement gas costs are prudently incurred. Therefore we grant Public Service a presumption of prudence for the procurement of replacement gas in the event Anadarko breaches the agreement. This presumption of prudence for replacement power assumes, of course, that the Company was prudent in its management of the contract leading up to the breach.

3. Additional Long-Term Contracts

229. Anadarko recommends that Public Service pursue additional long-term contracts, which, if undertaken at rates similar to the Anadarko Contract, will further reduce gas supply costs. *See* Moore Supplemental Answer Testimony (Hrg. Ex. 197).

230. Staff recommends that for another long-term contract in the future, given the volatility of natural gas prices and the long duration of the contract, Public Service should request bids in the RFP process with a one-time reset from the date of the bid to the date of the contract to ensure the chosen bid continues to be beneficial to its customers as the sole least cost bid option. Peabody concurs with such a price reset requirement, and suggests the Commission require approval of the RFP before it is issued by Public Service.

231. Public Service stated it would be open to additional contracts, although it should be within the Company's discretion to decide whether to pursue such additional contracting. *See* Tr. Oct. 28, 2010, at 204.

232. We find additional long-term gas contracts could provide value to the Company and its customers, particularly because the plan we approve today will likely lead to increased natural gas burn as compared to the Company's recommended scenario 5B. Therefore, we direct Public Service to investigate additional long-term natural gas supply contracts. However, we recognize that the decision to enter into additional long-term contracts is within the Company's management discretion.

J. Emissions Cap on New Resources

233. The GEO suggests the Commission rule that all future resources considered by the Company in its 2011 ERP achieve, at minimum, the emissions performance standards that are achieved by replacement resources in this plan. GEO SOP, at 14. In other words, the GEO argues the Company should only consider those resources that have an emissions profile equal to or better than a 2X1 CC natural gas plant. The Commission finds this suggestion is outside the scope of this Docket, which exists only to address the Company's emission reduction plan filed in accordance with HB 10-1365. As such, we decline to consider this proposal.

K. Transmission

234. In its SOP, Staff requests that Public Service develop a 10 to 12 year long-term study of the Denver-Boulder load serving network. Staff SOP, at 15. Staff believes the study should include, among other things, an evaluation of the severe overloads shown on Table 5 of Attachment TWG-1 of the rebuttal testimony of Company witness Tom Green. Hrg. Ex. 26, at 18. Staff asserts that the study should start immediately after a decision is entered in this Docket. Staff SOP, at 15.

235. We agree with Staff on this matter and require Public Service to develop a study of the Denver-Boulder area looking out 10 to 12 years. In addition, we request that Public Service solicit input from Staff about the scope of the study. This information will help inform the next resource plan proceeding and we direct Public Service submit the study as part of its next ERP filing.

236. Expanding this perspective, we further find it is important to begin developing a better understanding of how the transmission and generation system needs to develop over the next 20 to 30 years considering the projected growth and eastward expansion of the Colorado Front Range population center. In addition, the process going forward should not be limited to a dialog between the Commission and utilities but should also involve all stakeholders: developers, economic development organizations, local governments, etc. While we understand that Cherokee and Arapahoe will continue to play a key role, building a better understanding of how the system needs to develop as well as establishing the necessary communication channels will allow the Commission to better serve current and future ratepayers.

L. Classification of Information as Highly Confidential and Discovery Disputes

237. If a party believes information requires extraordinary protection, Rule 1100(a)(III) of the Commission's Rules of Practice and Procedure, 4 CCR 723-1, require the party to submit a motion to the Commission seeking such treatment. The Commission, upon viewing the information²⁸ and the motion *in camera*, may enter an order granting the motion and ordering the level of extraordinary protection which the Commission, in the exercise of its discretion, deems appropriate. Rule 1100(a)(I), 4 CCR 723-1. Requests for extraordinary protection are not routine, and we will grant them only if the moving party meets its high burden. *See* Decision No. C08-0237 at ¶ 15. *See also* Decision No. R07-0924 at ¶ 36.

238. The Commission's Rules regarding extraordinary protection are set forth to ensure the Commission is the final arbiter of what is and what is not deserving of extraordinary protection. This is not a determination parties may make without first obtaining an order from the Commission.

239. In the course of these proceedings, it came to the Commission's attention that the Company withheld certain reports prepared by its consultant from Staff, under the assertion that such documents were subject to extraordinary protection. *See* Tr. Oct. 25, 2010, at 94-104; Tr. Oct. 28, 2010, at 50-54. In this Docket, Staff was granted access to all highly confidential information, as it typically is. Nonetheless, Public Service undertook some delay in providing a highly confidential consultant's report to Staff, on the basis that the information was subject to a

²⁸ Parties seeking extraordinary protection may also provide a representative sample of the information or a description of the information. Rule 1100(a)(III), 4 CCR 723-1. However, the Commission may seek the actual information if it is necessary for the Commission to render a decision on the motion. Further, if the motion is granted, a complete version of the document shall be filed with the Commission. *Id.*

confidentiality agreement between the Company and its consultant. *See* Tr. Oct. 28, 2010, at 52-54.

240. The Commission wishes to remind the Company and other parties seeking extraordinary protection that a determination as to the level of protection afforded to a document is entirely within the Commission's discretion, and is not to be determined by any party. Further, where consistent with existing protective orders, such information should be provided to Staff without delay, and without regard to supplemental agreements the party seeking extraordinary protection may have.

241. An additional dispute came to the Commission's attention on November 19, 2010. Peabody raised concerns about the completeness of the Company's response to discovery requests propounded by itself, Climax/CF&I, and Staff.²⁹ The Commission has come to understand that, in responding to these discovery requests, Public Service narrowed the term "the Company" to include only certain departments that, in its opinion, were affected by the particular response. *See* Tr. Nov. 20, 2010, at 211-14. This occurred even though the Company was aware additional departments might be in possession of responsive information. *Id.* at 216. However, Public Service represented this type of narrowing is not the its typical practice in responding to discovery requests that seek information related to "the Company." *See Id.* at 212-14.

242. The Commission accepts Public Service's representation that this occurrence does not represent the Company's typical discovery practice. However, the Commission does not look favorably on parties attempting to impose artificial limitations on a particular request when

²⁹ *See* Statement of Known Facts and Circumstances, filed by Peabody on November 20, 2010. *See also* Tr. Nov. 19, 2010, at 301-35; Tr. Nov. 20, 2010, at 89-161; Tr. Nov. 20, 2010, at 209-234.

responding to discovery. The Company should take note and adopt appropriate precautions in the future to ensure its discovery responses are prompt and full.

M. Impacts on Coal-Producing Communities

243. At its highest level, HB 10-1365 is a major policy statement of the Colorado General Assembly. The legislation discusses the impact of the bill's implementation on the environment, the Colorado economy, resource development, Colorado's investor-owned utilities, and on utility rates. In its Legislative declaration, HB 10-1365 requires the Commission to address the impact of our decision on Colorado's energy-producing communities: "The general assembly also finds and declares that the actions provided for in this Part 2 be implemented in a manner to address the sound economic, health, and environmental conditions of energy producing communities." § 40-3.2-202(3), C.R.S.

244. In this Docket, we heard testimony from experts and citizens alike, expressing concern about the possible loss of jobs in the Colorado coal mining industry and the communities that support those workers. At the same time, we heard conflicting testimony that any lost sales of Colorado coal due to the plant closures ordered in this Docket will likely be made up with sales of Colorado coal into other markets.

245. The Commission is concerned about the impact of this Decision on the state's economy generally and any potential job losses in the coal industry in particular. We believe that the General Assembly intended for the Commission to be actively engaged with this issue. During the public hearing in Denver on September 23, 2010, we heard that the funding for worker retraining available to the Colorado Department of Labor is, at least at the moment, fairly depleted. Therefore, we begin a process with this Order that will lead, if it is needed, to

additional funding for the retraining of coal miners who may lose their jobs due to the Decision in this Docket.

246. We direct the Staff of the Commission to consult with the relevant entities, which may include the Colorado Department of Labor, CMA, AGNC, and the OCC, among others, to design an approach to the questions of how to ascertain the impact on mining employment of the Company's approved emission reduction plan and how to efficiently dedicate appropriate ratepayer funds to the effort of retraining eligible coal miners. Staff shall prepare and present a recommendation to the Commission before December 31, 2011.

II. ORDER

A. The Commission Orders That:

1. The emission reduction plan submitted by Public Service Company of Colorado (Public Service or Company) is modified and hereby approved.

2. Retirement of Cherokee 1 by 2011 is necessary and in the public interest for emission reduction purposes.

3. Within three months prior to the commencement of the Company's next electric base rate proceeding, Public Service shall file an application, consistent with the discussion above, to amend its Cherokee 1 Certificate of Public Convenience and Necessity (CPCN).

4. Retirement of Cherokee 2 by 2011 is necessary and in the public interest for emission reduction purposes.

5. Re-use of Cherokee 2 as a synchronous condenser and installation of a 90 MVAR capacitor bank is necessary and in the public interest for system stability and emission reduction purposes. Public Service shall carefully monitor the use of the synchronous condenser at Cherokee 2 during the implementation of the plan.

6. Within three months prior to the commencement of the Company's next electric base rate proceeding, Public Service shall file an application, consistent with the discussion above, to amend its Cherokee 2 CPCN.

7. Retirement of Cherokee 3 by 2015 is necessary and in the public interest for emission reduction purposes.

8. Within three months prior to the commencement of the Company's next electric base rate proceeding, Public Service shall file an application, consistent with the discussion above, to amend its Cherokee 3 CPCN.

9. Conversion of Cherokee 4 from coal-fired generation to natural gas-fired generation by the end of 2017 is necessary and in the public interest for emission reduction purposes.

10. Public Service is granted a presumption of need for a 2X1 combined cycle natural gas facility at Cherokee Station with respect to a future application for a CPCN.

11. Retirement of Arapahoe 3 by 2013 is necessary and in the public interest for emission reduction purposes.

12. Re-use of Arapahoe 3 as a synchronous condenser and installation of 90 MVAR of new shunt capacitors is necessary and in the public interest for system stability and emission reduction purposes.

13. Conversion of Arapahoe 4 from coal-fired generation to natural gas-fired generation by 2014 is necessary and in the public interest for emission reduction purposes.

14. Retirement of Valmont 5 by 2017 is necessary and in the public interest for emission reduction purposes.

15. Within three months prior to the commencement of the Commission's next electric base rate proceeding, Public Service shall file an application, consistent with the discussion above, to amend the Valmont 5 CPCN.

16. Installation of selective catalytic reduction (SCR), lime spray dryer, and sorbent injection controls at Pawnee by 2014 is necessary and in the public interest for emission reduction purposes.

17. Public Service shall file a modified application, consistent with the discussion above, for a CPCN for the controls to be installed at Pawnee. Public Service is granted a presumption of need for these controls with respect to this CPCN application.

18. Installation of SCR controls at Hayden 1 by 2015 is necessary and in the public interest for emission reduction purposes.

19. Public Service shall file a modified application, consistent with the discussion above, for a CPCN for the controls to be installed at Hayden 1. Public Service is granted a presumption of need for those controls with respect to this CPCN application.

20. Installation of SCR controls at Hayden 2 by 2016 is necessary and in the public interest for emission reduction purposes.

21. Public Service shall file a modified application, consistent with the discussion above, for approval of the controls to be installed at Hayden 2. Public Service is granted a presumption of need for those controls with respect to this CPCN application.

22. Public Service's request to adopt an Emissions Reduction Adjustment for Construction Work in Progress (CWIP) is rejected. Public Service shall be permitted to accumulate allowance for funds used during construction (AFUDC) and request actual recovery of the CWIP in a general rate case, consistent with the above discussion.

23. Public Service's request to use deferred accounting for accelerated depreciation and removal costs associated with the coal-fired electric generating units retired by this Order is adopted, consistent with the discussion above.

24. Public Service's request to use the jurisdictional allocator as it changes over time in the assignment to wholesale customers of their proportion share of House Bill 10-1365 costs is approved.

25. The long term natural gas contract between Public Service and Anadarko Energy Services Company (Anadarko) is approved. The Commission finds Public Service acted prudently in entering into the contract, the contract will provide a benefit to consumers, and approval of the contract is in the public interest.

26. Public Service is granted a presumption of prudence for the procurement of replacement gas in the event Anadarko breaches the long-term gas contract, so long as Public Service has prudently managed the contract.

27. Public Service shall develop a 10- to 12-year study of the Denver-Boulder load serving network, after soliciting input from Staff of the Commission regarding the scope of the study.

28. Consistent with the discussion herein, Staff of the Commission shall consult with appropriate entities and then inform the Commission of a recommended structure and funding of a program to assist in retraining Colorado mining industry employees if mining jobs are lost as a result of the implementation of the Company's modified and approved emission reduction plan.

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

30. This Order is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING
December 9, 2010.**

(S E A L)



ATTEST: A TRUE COPY

A handwritten signature in cursive script that reads "Doug Dean".

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

RONALD J. BINZ

JAMES K. TARPEY

MATT BAKER

Commissioners