To see the entire attachment go here:
http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheader=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251700593372&ssbinary=true

Attachment A

A G E N D A

Legislative Council

Friday, March 25, 2011
1:30 p.m.

House Committee Room 0112
State Capitol Building
Denver, CO 80203

Call to Order

I. Review of State Implementation Plan (SIP)

- *Tom Morris, Office of Legislative Legal Services*

Other Business

Adjourn

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LEGAL MEMORANDUM

TO: Legislative Council

FROM: Office of Legislative Legal Services

DATE: March 16, 2011

SUBJECT: H.B. 10-1365 and Regional Haze State Implementation Plan[1]

QUESTIONS PRESENTED

1. Are any of the issues raised by the legislators who requested a state implementation plan (**SIP**)[2] hearing within the scope of review for a SIP hearing as established by section 25-7-133 (2) (a), C.R.S.? In particular, do the portions of the regional haze SIP that relate to House Bill 10-1365 (**H.B. 1365**) violate section 25-7-105.1 (1), C.R.S., by including in the SIP requirements that are more stringent than or otherwise not required by the federal "Clean Air Act" (the **Federal Act**)?

2. With regard to the regional haze SIP, what requirements did H.B. 1365 impose on electric utilities, the Public Utilities Commission (**PUC**), and the Air Quality Control Commission (**AQCC**)?

3. What did the AQCC do in response to the requirements of H.B. 1365?

4. What procedural options does Legislative Council have with regard to the SIP hearing, and what are the effects of those options on the status of the SIP?

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[1] This legal memorandum results from a request made to the Office of Legislative Legal Services (OLLS), a staff agency of the General Assembly. OLLS legal memoranda do not represent an official legal position of the General Assembly or the State of Colorado and do not bind the members of the General Assembly. They are intended for use in the legislative process and as information to assist the members in the performance of their legislative duties.

[2] **Attachment 1** contains a list of all acronyms and abbreviations used in this memorandum.

SHORT ANSWERS

1. Several of the issues raised by the legislators' letters appear to be beyond the scope of this SIP hearing as established by section 25-7-133 (2) (a), C.R.S. This memorandum does not address the ultimate issue of whether the regional haze SIP accomplishes the results intended by H.B. 1365. However, the issue of whether the regional haze SIP violates section 25-7-105.1 (1), C.R.S., by including requirements that are more stringent than or not required by what is currently required by the Federal Act does appear to be within the scope of the SIP hearing.

2. Both of the state's two rate-regulated utilities, Public Service Company of Colorado (**PSCo**), and Black Hills/Colorado Electric Utility Company LP, had to submit an air emissions reduction plan by August 15, 2010, that covered the lesser of 900 megawatts or 50% of the utility's coal-fired electric generating units. Both plans had to meet the current and reasonably foreseeable requirements of the Federal Act and state law and be fully implemented by December 31, 2017. The department of public health and environment (**Department**) had to determine whether any new or repowered electric generating unit proposed under the plan will achieve emission rates equivalent to or less than a combined-cycle natural gas generating unit. The PUC had to determine, based on the Department's input, whether the plan is likely to achieve at least a 70 to 80% reduction in annual emissions of nitrogen oxides and enter an order approving, denying, or modifying the plan by December 15, 2010. The AQCC had to incorporate the air quality provisions of the utility plan into the regional haze element of the SIP.

3. The Department concluded that the utilities' plans meet the 70 to 80% nitrogen oxides reduction standard and meet the reasonably foreseeable requirements of the Federal Act. The AQCC promulgated rules to incorporate the air quality provisions of the utility plans, as approved by the PUC, into the regional haze element of the SIP. The rules require the utilities to retire 7 coal-fired electric generating units, to replace some of their capacity with a new combined cycle natural gas-fired generation unit and a peaking gas-fired generation unit, to install emission controls on 3 coal-fired units, and to convert two coal-fired units to burn natural gas.

4. Legislative Council can (1) take a vote to introduce a bill or bills to affect the regional haze SIP, either by approving or disapproving it; or

(2) take no action. If no vote is taken, or a vote is taken and no bill is enacted, or a bill is enacted to approve the SIP, the federal environmental protection agency (**EPA**) can approve the SIP. If a bill is enacted to disapprove the SIP, EPA cannot approve the SIP and the AQCC will have to promulgate another SIP pursuant to the terms of the enacted bill.

I. INTRODUCTION

Last year the General Assembly enacted H.B. 1365, which stated in its legislative declaration that the Federal Act:

> will likely require reductions in emissions from coal-fired power plants operated by rate-regulated utilities in Colorado. A coordinated plan of emission reductions from these coal-fired power plants will enable Colorado rate-regulated utilities to meet the requirements of the federal act and protect public health and the environment at a lower cost than a piecemeal approach. A coordinated plan of reduction of emissions for Colorado's rate-regulated utilities will also result in reductions in many air pollutants and promote the use of natural gas and other low-emitting resources to meet Colorado's electricity needs, which will in turn promote development of Colorado's economy and industry.

§40-3.2-202 (1), C.R.S. H.B. 1365 required rate-regulated electric utilities to submit air emission reduction plans to the PUC. The plans had to cover the lesser of half of the utilities' coal-fired electric generating units or 900 megawatts of power, result in designated emissions reductions, and meet certain other standards. After the PUC approved the plans, the AQCC was required to incorporate the air quality provisions of the plans into the regional haze element of the SIP. The AQCC submitted a summary report on the regional haze SIP (**Attachment 2**) to the General Assembly on January 15, 2011.

State law allows any member of the General Assembly to request that Legislative Council hold a hearing on a SIP to determine whether the "addition or change to the SIP element accomplishes the results intended by enactment of the statutory provisions under which the addition or change to the SIP element was adopted." §25-7-133 (2) (a), C.R.S.[3] Two sets of legislators requested such a hearing pursuant to letters dated February 11, 2011 (the **J. Kerr Letter**), and February 14, 2011 (the **Renfroe Letter**).[4]

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[3] Section 25-7-133 (1) and (2), C.R.S., is **Attachment 3**.

[4] The J. Kerr Letter and the Renfroe Letter are **Attachment 4**.

This intent of this memorandum is to provide Legislative Council with information to facilitate its deliberations in the SIP hearing. The memorandum will cover the following issues:

1. An overview of background issues, including the applicable requirements of the Federal Act and the state clean air act, article 7 of title 25, C.R.S. (the **State Act**);

2. An analysis of whether the issues raised by the J. Kerr and Renfroe Letters are within the scope of the SIP hearing;

3. The requirements of H.B. 1365;

4. A brief summary of the actions taken in response to H.B. 1365 by the affected utilities, the PUC, the Department, and the AQCC; and

5. A statement of the potential actions that the Legislative Council may take and the effects of those actions on the status of the SIP.

II. BACKGROUND: CLEAN AIR REQUIREMENTS

A. Federal Act Requirements: SIPs, Ambient Standards, Regional Haze, and Emission Controls

1. SIPs and Ambient Standards

The Federal Act contains numerous requirements, both for sources of air pollutants and for states. In particular, the Federal Act creates a "floor" or minimum level of stringency that state air quality laws must attain, and states are required to adopt SIPs that meet or exceed this floor. States must meet this minimum level of stringency or EPA will impose sanctions, including the withholding of federal grant moneys and the adoption of a federal implementation plan that would be enforced in lieu of the SIP. If EPA determines that a SIP is adequate, EPA promulgates the SIP in the code of federal regulations (which makes the SIP enforceable as federal law) and delegates to the state the authority to implement its SIP. EPA promulgated Colorado's SIP at 40 C.F.R. §52.320.

SIPs are required for pollutants for which EPA has promulgated a national ambient air quality standard (**NAAQS**), including ozone, sulphur dioxide, nitrogen oxides, and particulate matter (**criteria pollutants**), and for visibility. Colorado is currently out of compliance with the NAAQS for ozone,

and EPA has proposed an even more stringent NAAQS for ozone, for which Colorado will need to adopt an updated SIP sometime in 2013. EPA adopted a more stringent NAAQS for sulphur dioxide in June of 2010, and the AQCC anticipates that EPA will be promulgating a more stringent NAAQS for particulate matter in the foreseeable future.

2. Regional Haze and BART

One of the main requirements of the Federal Act is the prevention of significant deterioration (**PSD**) program, the goal of which is to keep clean air clean. One element of the PSD program is the visibility program. The goal of the visibility program is to protect long-range visibility in certain national parks and wilderness areas that are listed by EPA (**Class I areas**). Colorado has 12 of the 156 Class I areas nation-wide.

In 1999, EPA promulgated a regional haze rule that regulates large air pollutant sources that have wide, regional impacts on visibility in Class I areas. The rule requires these sources, which have the potential to emit at least 250 tons per year of a visibility-impairing pollutant, to undergo a source-by-source review to determine the best available retrofit technology (**BART**) that the source must install. As an alternative to a source-by-source review, a state can adopt a programmatic BART alternative that results in greater reasonable progress toward visibility improvements than would result from a source-by-source review. EPA disapproved Colorado's regional haze SIP on January 15, 2009, and required submission of a new regional haze SIP by January 15, 2011. The SIP that is the subject of this hearing is the SIP that the AQCC is submitting to EPA in response to this requirement.

3. Emission Controls: MACT, NSPS, and BACT

Finally, as relevant here, the Federal Act also imposes the following different types of emission control requirements:

1. Major sources of hazardous air pollutants (**HAPs**), such as mercury, must install maximum available control technology (**MACT**). EPA has already promulgated a MACT standard for electric utilities' mercury emissions, and EPA has just proposed a MACT standard for coal-fired electric generating units and anticipates that it will finalize the standard by November 2011;

2. New air pollutant sources that are specifically listed by the EPA, such as coal-fired electric generating units, must meet EPA's new source performance standards (**NSPS**), which EPA has just

proposed to revise; and

3. Major sources of criteria pollutants that are located in areas that are in attainment for a NAAQS (**PSD areas**) and that do not affect a Class 1 area must install best available control technology (**BACT**) for such criteria pollutant. EPA also recently promulgated a rule that requires major sources of greenhouse gases (**GHG**), such as electric utilities, to undergo BACT review for GHG in PSD areas.

B. State Act Requirements: Federal Enforceability and the SIP Review Process

The State Act gives the AQCC broad, general authority to adopt emission control regulations and SIPs in order to comply with the minimum elements of the Federal Act. Part 2 of the State Act contains Colorado's PSD program, the SIPs for which are required to be consistent with EPA's requirements.

Once EPA approves a SIP element, even if the element is not required by the Federal Act, neither the AQCC nor the General Assembly can unilaterally remove the element. Instead, the AQCC must submit a SIP revision that must demonstrate to EPA's satisfaction that the revision will not impair Colorado's ability to comply with applicable requirements. Consequently, the General Assembly has enacted two laws to ensure that SIPs contain only those provisions that are intended to be included.

1. Federal Enforceability

The first law specifies that our SIPs cannot include requirements that are more stringent than are required under the Federal Act. Section 25-7-105.1 (1), C.R.S., states:

> **25-7-105.1. Federal enforceability.** (1) **To the extent that any provision of this article or any standard or regulation promulgated pursuant thereto is not required by** Part C (prevention of significant deterioration), Part D (nonattainment), or Title V (minimum elements of a permit program) of the federal act, or is not required by section 111 of the federal act, or is not required for sources to participate in the early reduction program of section 112 of the federal act, or is not required for sources to be excluded as a major source under this article, **or is otherwise more stringent than other requirements of the federal act,** such provision, standard, or regulation is hereby declared to be adopted under powers reserved to the state of Colorado pursuant to section 116 of the federal act. Any **such provision, standard, or regulation** adopted

exclusively under state authority **shall not constitute part of the state implementation plan.** (Emphasis added)

Under this provision, the federal floor for SIPs becomes, in effect, a state ceiling. While there are portions of state law that impose air quality requirements that are more stringent than or otherwise not required by federal law, pursuant to section 25-7-105.1 (1), C.R.S., absent a law that creates an exception to section 25-7-105.1, C.R.S., these requirements are not part of the SIP and consequently are not federally enforceable.

2. SIP Review Process

The second law, section 25-7-133 (1) and (2), C.R.S. (**Attachment 3**), creates a special Legislative Council SIP review process. The AQCC must submit a summary report of each new or revised SIP by January 15 of each year. Any legislator can request a hearing by Legislative Council by submitting a written request by February 15. Legislative Council must hold the hearing if one is requested and may vote to introduce a bill or bills to affect the SIP. If Legislative Council does not vote to introduce a bill, a legislator who submitted the written request may, within 3 days after action by Legislative Council to not introduce a bill, file written notice of intent to file a bill (which is exempt from the 5-bill limit) to affect the SIP.

If a bill is introduced in either of these two ways, the AQCC can submit the SIP to EPA only provisionally until the legislative process is resolved. Additionally, any legislator can, at any point, introduce a bill (which is exempt from the 5-bill limit) to affect the SIP without having submitted a SIP hearing request and regardless of whether Legislative Council has introduced a bill, but the introduction of a bill in this manner does not prevent the AQCC from submitting the SIP to EPA unconditionally.

Pursuant to section 25-7-133 (2) (a), C.R.S., two groups of legislators submitted letters (the J. Kerr Letter and the Renfroe Letter) that requested a SIP hearing and raised a variety of issues relating to H.B. 1365 and the regional haze SIP. The next section of this memorandum analyzes these issues.

III. LETTER ISSUES

A. Scope of SIP Hearing

Section 25-7-133 (2) (a), C.R.S. (Attachment 3), states that "any member of the general assembly may make a request in writing to the

chairperson of the legislative council that the legislative council hold a hearing or hearings to review any addition or change to elements of the SIP contained in the report submitted pursuant to subsection (1) of this section.".

Although the regional haze SIP (a summary report of which is Attachment 2) contains elements that are not related to H.B. 1365, both the J. Kerr Letter and the Renfroe Letter referred only to the aspects of the regional haze SIP that relate to H.B. 1365[5]. Further, H.B. 1365 contains many requirements that do not relate to air quality issues and were not included in the regional haze SIP, such as utility customer rate impacts, overall cost, utility cost recovery, electric system reliability, long-term gas supply agreements, the economic impacts of the plans, and procedural requirements for the PUC's determinations. H.B. 1365's essential requirement that does relate to the SIP is the requirement that the AQCC "incorporate the air quality provisions of the utility plan into the regional haze element of the state implementation plan." §40-3.2-208 (2) (a), C.R.S.

Additionally, neither Letter referred to Black Hills/Colorado Electric Utility Company LP, which is one of the two rate-regulated electric utilities in Colorado that are subject to H.B. 1365; both referred only to the emissions reduction plan of PSCo, the other utility that is subject to H.B. 1365.

Therefore it is reasonable to conclude that the "addition or change to elements of the SIP" with regard to which the legislators requested a hearing is the air quality provisions of PSCo's emission reduction plan, as approved by the PUC, that the AQCC incorporated into the regional haze element of the SIP. Thus, the scope of the SIP hearing appears to be limited to that issue. Several of the issues addressed in the Letters, such as the time line of the emission reduction plans' approval, compliance with the "State Administrative Procedures Act", retail rate impacts, and impacts on energy-producing communities, appear to be outside of the scope of this SIP hearing as contemplated by section 25-7-133 (2) (a), C.R.S.

This memorandum does not address the ultimate issue of whether the regional haze SIP accomplishes the results intended by H.B.1365. However, the issue raised in the J. Kerr Letter relating to whether the SIP violates section 25-7-105.1 (1), C.R.S., by including "requirements that are more stringent than what is currently required" by the Federal Act, does appear to be within the scope of this SIP hearing; the following section addresses this issue.

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[5] H.B. 1365, part 2 of article 3.2 of title 40, C.R.S., is **Attachment 5**.

B. Violation of Section 25-7-105.1 (1), C.R.S.

Section 25-7-105.1 (1), C.R.S. (quoted in full above at pages 6 and 7), states that to the extent that "any provision of this article or any standard or regulation promulgated pursuant thereto is not required by . . . or is otherwise more stringent than other requirements of the federal act, . . . such provision, standard, or regulation . . . shall not constitute part of the state implementation plan.". The discussion on page 7 concluded that, absent a law that creates an exception to section 25-7-105.1 (1), C.R.S., requirements that are more stringent than or not required by the Federal Act cannot be part of the SIP.

Section 25-7-110.5 (5) (a), C.R.S., of the State Act requires the AQCC to specify in a "detailed, footnoted explanation" whenever the AQCC proposes any rule that "exceeds the requirements" of the Federal Act. The AQCC concluded, in its Statement of Basis, Specific Statutory Authority, and Purpose for the regional haze rules, that the regional haze SIP does not contain provisions that exceed the Federal Act, and thus that section 25-7-110.5 (5) (a), C.R.S., does not apply.[6] There would be no violation of section 25-7-105.1 (1), C.R.S., if the AQCC's conclusion is valid.

There is, however, a cogent argument that the regional haze SIP does include requirements that are more stringent than or not required by the Federal Act. First, as explained above on page 5, a BART alternative is a regulatory option under the Federal Act that results in greater reasonable progress toward visibility improvements than would result from a normal source-by-source BART review. "Greater reasonable progress" is presumably achieved through more stringent regulatory requirements. The regional haze SIP includes a BART alternative requirement for 5 coal-fired electric generating units that are not otherwise subject to BART.[7] By subjecting these sources to the BART alternative, the regional haze SIP arguably violates section 25-7-105.1 (1), C.R.S.

Second, pursuant to section 40-3.2-204 (2) (b) (IV), C.R.S., of H.B. 1365, PSCo's plan had to meet not only the current requirements of the Federal Act, but also those requirements that are "reasonably foreseeable" as determined by the Department. "Reasonably foreseeable" requirements are, by definition, not "currently applicable" requirements, and therefore the regional haze SIP appears to include elements that are not currently required

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[6] The Statement (along with an excerpt of the amended rules) is **Attachment 6**.

[7] Those units are Arapahoe 3 and 4 and Cherokee 1, 2, and 3. *See* Attachment 6.

by the Federal Act.

On the other hand, to the extent that the portions of the regional haze SIP that relate to H.B. 1365 do create requirements that are not required by or are more stringent than the Federal Act, those portions are, at least arguably, directly required by H.B. 1365. As noted above, for purposes of this SIP hearing, the essential requirement of H.B. 1365 is the requirement that the AQCC "incorporate the air quality provisions of the utility plan into the regional haze element of the state implementation plan." §40-3.2-208 (2) (a), C.R.S. Under this analysis, H.B. 1365 required the regional haze SIP to include requirements that are not required by or are otherwise more stringent than required by the Federal Act.

Because sections 40-3.2-204 (2) (b) (I) and 25-7-105.1 (1), C.R.S., must be construed together, the later-enacted and more specific provisions of section 40-3.2-204 (2) (b) (I), C.R.S., can be construed as an exception to the general prohibition of section 25-7-105.1 (1), C.R.S. Therefore, the SIP would not violate section 25-7-105.1 (1), C.R.S., by including requirements that are more stringent than or not required by what is currently required by the Federal Act, because H.B. 1365 explicitly requires the SIP to include such requirements.

IV. HOUSE BILL 1365

As the legislative declaration for H.B. 1365 (quoted above on page 3) states, the currently applicable and reasonably anticipated requirements of the Federal Act will require expensive upgrades to Colorado's electrical generation system, a significant portion of which consists of coal-fired electric generating units, some of which are nearing the end of their expected useful life. H.B. 1365 was intended to reduce these costs by comprehensively planning for emissions reductions rather than reacting to federal requirements as they become due.

The following sections quote the main air quality-related requirements of H.B. 1365 with regard to rate-regulated utilities, the PUC, and the AQCC. (Within H.B. 1365, "commission" refers to the PUC and "department" refers to the department of public health and environment.)

A. Rate-regulated Utility Requirements

The following provisions of section 40-3.2-204, C.R.S., impose requirements on rate-regulated electric utilities:

(1) **On or before August 15, 2010**, and in coordination with

current or expected requirements of the federal act and the state act, **all rate-regulated utilities that own or operate coal-fired electric generating units located in Colorado shall submit to the commission an emission reduction plan** for emissions from those units.

(2) (a) **The plan** filed under this section **shall cover** a minimum of **nine hundred megawatts or fifty percent of the utility's coal-fired electric generating units in Colorado, whichever is smaller**. . . .

. . . .

(b) (I) Prior to filing the plan, **the utility shall consult with the department** and shall work with the department in good faith **to design a plan to meet the current and reasonably foreseeable requirements of the federal act and state law** in a cost-effective and flexible manner.

. . . .

(c) The plan shall include a schedule that would result in **full implementation of the plan on or before December 31, 2017**. The schedule may include interim milestones. The utility shall design the schedule to protect system reliability, control overall cost, and assure consistency with the requirements of the federal act.

(d) **The plan shall set forth the costs** associated with activities identified in the plan, including the planning, development, construction, and operation of elements identified pursuant to subparagraphs (I) to (IX) of paragraph (a) of this subsection (2), as well as the costs of any shutdown, decommissioning, or repowering of existing coal-fired electric generating units that are set forth in the plan. (Emphasis added)

Rate-regulated electric utilities are also subject to the following requirements of section 40-3.2-206, C.R.S.:

(1) (a) . . . . in **the plan** required under section 40-3.2-204, each utility **shall include an evaluation of** the following proposals:

(I) **The cost and system reliability impacts of** retiring a minimum of nine hundred megawatts of coal-fired electric generating capacity, or fifty percent of the utility's coal-fired generating units in Colorado, whichever is less, by January 1, 2015, and **repowering the affected coal-fired facilities with natural gas or replacing them with natural gas-fired generation or other low-emitting resources**, including energy efficiency. . . .

(II) Retirements of a portion of its coal-fired generating capacity in the period after April 19, 2010, but prior to January 1, 2015. At a minimum, **the utility shall evaluate** whether to retire a portion of its coal-fired capacity on or before January 1, 2013, or **whether the retirements of coal-fired generating facilities that have already been announced could be advanced to an earlier retirement date**.

(2) **The utility shall set forth in its plan** the utility's proposal for **the best way of timely meeting the emission reduction requirements required by federal and state law,** given the need to preserve electric system reliability, to avoid unreasonable rate increases, and the economic and environmental benefits of coordinated emission reductions. (Emphasis added)

B. PUC Requirements

Pursuant to section 40-3.2-204 (2) (b) (IV), C.R.S., the PUC "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 act." The following provisions of section 40-3.2-205, C.R.S., impose further requirements on the PUC:

> (1) In evaluating the plan, **the commission shall consider the following factors:**
>
> (a) **Whether** the department 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** as necessary to comply with current and reasonably foreseeable requirements of the federal act and the state act. The reduction in emissions under this paragraph (a) shall be measured from 2008 levels at coal-fired power plants identified in the plan. . . . (b) **Whether the department has made the determination under section 40-3.2-204 (2) (b) (III)**;
>
> (c) The degree to which the plan will result in reductions in other air pollutant emissions;
>
> (d) The degree to which the plan will increase utilization of existing natural gas-fired generating capacity;
>
> (e) 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;
>
> (f) Whether the plan promotes Colorado economic development;
>
> (g) Whether the plan preserves reliable electric service for Colorado consumers;
>
> (h) Whether the plan is likely to help protect Colorado customers from future cost increases, including costs associated with reasonably foreseeable emission reduction requirements; and
>
> (i) Whether the cost of the plan results in reasonable rate impacts. In evaluating the rate impacts of the plan, the commission shall examine the impact of the rates on low-income customers.
>
> (2) **The commission shall** review the plan and **enter an order approving, denying, or modifying the plan by December 15, 2010.** Any modifications required by the commission shall result in a plan that the department determines is likely to meet current and reasonably foreseeable federal and state clean air act requirements. (Emphasis added)

C. AQCC and Department Requirements

Section 40-3.2-204 (2) (b) (III), C.R.S., requires the Department 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**. (Emphasis added)

The AQCC is subject to the following requirements of section 40-3.2-208, C.R.S., which is set forth in its entirety:

> **40-3.2-208. Air quality planning.** (1) **The air quality provisions of the emission reduction plan** filed under this part 2 **are intended to fulfill the requirements of the state and federal acts** and shall be proposed by the department to the air quality control commission after the utility files the plan with the commission to be considered for incorporation into the regional haze element of the state implementation plan.
>
> (2) (a) Upon the utility's filing of the utility plan with the commission pursuant to section 40-3.2-204, **the air quality control commission**, in response to the proposal by the department, **shall** initiate a proceeding to **incorporate the air quality provisions of the utility plan into the regional haze element of the state implementation plan.** Except as set forth in this subsection (2), the air quality control commission shall not act on the utility plan or the provisions of the regional haze element of the state implementation plan that would establish controls for those units covered by the utility plan until after the commission's approval of the utility plan.
>
> (b) The air quality control commission shall vacate the entire proceeding related to the utility plan and shall initiate a new proceeding for the consideration of alternative proposals for the appropriate controls for those units covered by the utility plan for inclusion in the regional haze element of the state implementation plan **if**:
>
> (I) The commission does not approve the utility plan by December 15, 2010;
>
> (II) The utility withdraws its application pursuant to section 40-3.2-205 (4); or
>
> (III) The air quality control commission rejects any portion of the utility plan as approved by the commission.
>
> (c) The air quality control commission shall conduct the proceedings specified in this subsection (2) after public notice and an opportunity for the public to participate in accordance with the air quality control commission's procedures.
>
> (3) **If** the final approved provisions of the state implementation plan are not consistent with the air quality provisions of the utility plan, the utility may file a revised utility plan with the commission that modifies the original plan to be consistent with the final approved state implementation plan. The revised utility plan is subject to all of the review and cost recovery provisions contained in this part 2. Notwithstanding any revision required to the utility plan, the utility is entitled to fully recover any costs it prudently incurred or contracted to incur under the originally approved plan prior to the plan's revision and any costs incurred as a result of any enforceable state implementation plan or other air quality requirements. (Emphasis added)

None of the conditions specified in subsection (2) (b) or the first sentence of subsection (3) occurred.

V. ACTIONS TAKEN IN RESPONSE TO H.B. 1365

A. Electric Utilities' Actions

One of the two rate-regulated electric utilities in Colorado that are subject to H.B. 1365, PSCo, submitted its emission reduction plan on August 13, 2010.[8] PSCo's plan presented a variety of scenarios; the scenario, with modifications, that the PUC ultimately adopted is discussed in detail below.

B. PUC's Actions

The PUC entered an order, Decision No. C10-1328, essentially approving scenario 6E FS from PSCo's plan, as modified, on December 9, 2010. **Attachment 7** is an excerpt of the Decision.[9] The Decision contains extensive and detailed findings about compliance with specific requirements of H.B. 1365 (Section I.G., ¶¶157 to 185). The Decision requires PSCo to:

- Retire 4 coal-fired electric generating units (Valmont 5, ¶¶119, 139; Cherokee 1 and 2, ¶¶108, 139; and Cherokee 3, ¶¶111, 139), to replace them with 569 megawatts of combined cycle natural gas-fired generation at the Cherokee Station, and to retire another coal-fired unit, Arapahoe 3 (¶114);[10]

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[8] Because the J. Kerr and Renfroe Letters do not refer to the other rate-regulated electric utility in Colorado that is subject to H.B. 1365, Black Hills/Colorado Electric Utility Company LP (Black Hills), this memorandum does not discuss Black Hills except in this footnote. Black Hills submitted its emission reduction plan on August 13, 2010. The plan proposed to either convert both of its coal-fired electric generating units, located at the Clark Station, to combust woody biomass by December 31, 2017, or to retire them both and to replace the generating capacity with natural gas-fired generation by January 1, 2015, or December 31, 2013. On December 1, 2010, the PUC entered an order approving Black Hills' plan, as modified, to retire both units and to replace the generating capacity with a natural gas-fired generating unit, would be used as a peaking rather than a baseload unit, by January 1, 2013. Decision No. C10-1330. The AQCC promulgated a rule on January7, 2011, to incorporate the air quality provisions of Black Hills' plan into the regional haze element of the SIP by requiring closure of the Clark Station units by December 31, 2013. AQCC Regulation 3, 5 CCR 1001-5 Part F, Rule VI.B.2.

[9] The full decision is available at the PUC's website: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=14999

[10] On January 26, 2011, the PUC entered an order, Decision No. C11-0121, that modified the retirement dates of Cherokee 1 to December 31, 2012 (¶58) and of Cherokee 3 to December 31, 2016 (¶64). That decision is available at: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=15186

- Install emission controls on 3 coal-fired units (Pawnee, ¶123; and Hayden 1 and 2, ¶128); and

- Convert two coal-fired units to burn natural gas (Cherokee 4, ¶134; and Arapahoe 4, ¶114).

The Decision covers 1,645 megawatts of coal-fired generating capacity, ¶163, and requires full implementation by December 31, 2017, ¶166. **Attachment 8** contains 3 exhibits from PUC's administrative process that establish the technical air quality-related aspects of the approved plan that respond to the 900 megawatt requirements of section 40-32.-204 (1) (a), C.R.S., and the 70 - 80% NOx reduction requirement of section 40-3.2-205 (1) (a), C.R.S.

C. AQCC's Actions

The Department testified during PUC's deliberations that all of PSCo's scenarios, including 6E FS, meet the 70 to 80% nitrogen oxides reduction standard of section 40-3.2-205 (1) (a), C.R.S., and that the scenarios meet the reasonably foreseeable requirements of the Federal Act as required by section 40-3.2-204 (2) (b) (I) and (2) (b) (IV), C.R.S. Attachment 7, ¶¶101, 164, 165.

On January 7, 2011, the AQCC promulgated amendments to Regulation 3, 5 CCR 1001-5 Part F, to incorporate the air quality provisions of PSCo's plan, as modified by the PUC, into the regional haze element of the SIP as required by section 40-3.2-208 (2) (a), C.R.S. An excerpt of these amendments is **Attachment 6**. Rule VI.A relates to Hayden 1 and 2 and requires, as a BART determination, that PSCo install selective catalytic reduction emission control technology on those units. Rule VI.C relates to all of PSCo's other coal-fired generating units that are subject to the Decision and requires, as a BART alternative determination, that PSCo either shut down the units or convert the units to combust natural gas. A table summarizing Decision No. C10-1328 and the AQCC's incorporation of the Decision into the SIP is **Attachment 9**.

List of Attachments

ATTACHMENT 1
List of Acronyms and Abbreviations

AQCC	Air Quality Control Commission
BACT	Best Available Control Technology - required to be installed by a major source of criteria pollutants that is in a PSD area and that does not affect Class 1 areas
BART	Best Available Retrofit Technology - required to be installed by major sources of criteria pollutants that affect visibility in Class I areas
Class I areas	Certain national parks and wilderness areas listed by EPA
Criteria pollutant	An air pollutant for which EPA has promulgated a NAAQS (e.g., ozone, sulphur dioxide, nitrogen oxides, and particulate matter)
EPA	Environmental Protection Agency
Federal Act	The federal "Clean Air Act", 42 U.S.C. sec. 7401 et seq.
GHG	Greenhouse Gases, major sources of which must undergo BACT review
HAPs	Hazardous Air Pollutants, major sources of which must install MACT
H.B. 1365	The "Clean Air - Clean Jobs Act", part 2 of article 3.2 of title 40, C.R.S.
Kerr Letter	Letter dated February 11, 2011, that requested a SIP hearing
NAAQS	National Ambient Air Quality Standard - promulgated by EPA for criteria pollutants
NSPS	New Source Performance Standards - an emission control regulation promulgated by EPA for particular types of sources, including coal-fired electric generating units
PSCo	Public Service Company of Colorado
PSD	Prevention of Significant Deterioration - an air quality program for areas that meet NAAQS and therefore already have clean air
Renfroe Letter	Letter dated February 14, 2011, that requested a SIP hearing
SIP	State Implementation Plan - how a state proposes to meet NAAQS and visibility requirements
State Act	The "Colorado Air Pollution Prevention and Control Act", article 7 of title 25, C.R.S.

ATTACHMENT 2

Air Quality
Regional Haze State Implementation Plan
Revisions Report

Submitted pursuant to the provisions of

C.R.S. 25-7-133

Submitted to the Colorado Legislative Council
By the Air Quality Control Commission
January 14, 2011

INTRODUCTION

Under the Colorado Air Pollution Prevention and Control Act, the Colorado Air Quality Control Commission (AQCC or Commission) is charged with the development of a comprehensive state implementation plan (SIP), which will assure attainment and maintenance of National Ambient Air Quality Standards and other aspects of the federal Clean Air Act. This plan must meet all the requirements of the federal Clean Air Act and shall be revised when necessary and appropriate. See § 25-7-133, C.R.S. As required by the Clean Air Act, any revisions to Colorado's SIP must be submitted to the United States Environmental Protection Agency (EPA) for review and approval. Under state law, prior to submitting any SIP revisions to EPA, and by January 15th of each year, the Commission must submit a report to the chairperson of the Legislative Council summarizing any changes or additions to the SIP that were adopted during the prior year. See § 25-7-133, C.R.S. Pursuant to this statutory directive the Commission submits the following report describing its revisions to Colorado's Regional Haze SIP.

STATUTORY REQUIREMENT

Section 25-7-133(1), C.R.S. sets forth the requirements governing the AQQC's annual SIP Revisions Report as follows:

> Notwithstanding any other provision of law but subject to subsection (7) of this section, by January 15 of each year the commission shall certify in a report to the chairperson of the legislative council in summary form any additions or changes to elements of the state implementation plan adopted during the prior year that are to be submitted to the administrator for purposes of federal enforceability. Such report shall be written in plain, nontechnical language using words with common and everyday meaning that are understandable to the average reader. Copies of such report shall be available to the public and shall be made available to each member of the general assembly. The provisions of this section shall not apply to control measures and strategies that have been adopted and implemented by the enacting jurisdiction of a local unit of government if such measures and strategies do not result in mandatory direct costs upon any entity other than the enacting jurisdiction.

STATE IMPLEMENTATION PLAN REVISION

After a series of public hearings, the Commission adopted revisions to Colorado's Regional Haze State Implementation Plan on January 7, 2011, which are being submitted for legislative review and approval pursuant to Section 25-7-133(1), C.R.S.

The Regional Haze Program is designed to achieve visibility improvements in areas of great scenic importance in Colorado such as national parks and wilderness areas. There are 12 such

areas (known as Class I areas) in Colorado, including Rocky Mountain National Park, Mesa Verde National Park and the Weminuche wilderness area. As required under the federal Clean Air Act, States must develop and periodically update their Regional Haze SIPs in order to implement emission control strategies that will achieve gradual improvement of visibility in designated Class I areas. Pursuant to 40 C.F.R. 51.308(b) Colorado was originally required to submit a Regional Haze State Implementation Plan to EPA no later than December 17, 2007. The Commission adopted a Regional Haze SIP in 2007, and later revised that SIP in 2008 because of identified deficiencies. Subsequently, EPA published a Federal Register Notice on January 15, 2009, that requires Colorado and 36 other states to submit revised SIPs by early 2011. Failure to submit an approvable SIP within this timeframe will subject Colorado to a Federal Implementation Plan (FIP) issued by EPA. Under a FIP, EPA would establish its own emission reduction strategies for Colorado sources without input from the state.

In order to meet the requirements of the 2009 Federal Register Notice, as well as the underlying federal statutory and regulatory requirements governing the Regional Haze Program, Colorado must submit a SIP containing a number of specific elements. First and foremost, the state must establish Best Available Retrofit Technology (BART) requirements for certain specifically identified large stationary sources in Colorado.[1] Under the Clean Air Act, BART for each of these sources must be determined based on consideration of a set of specific factors. This consideration includes an assessment of the costs and anticipated visibility improvements associated with each of the various technologically feasible emission reduction options for a specific source. As an option to complying with BART for each required source, the owner of a group of sources, including non-BART sources, can propose, and Colorado can adopt a BART Alternative that achieves greater emission reductions than imposition of BART on each of the individual sources. The BART Alternative option provides sources with flexibility in reducing emissions, and allows the owner of such sources to achieve additional emission reductions that may later be required under applicable federal and state clean air laws. In addition to establishing BART or BART Alternative requirements for specified sources, Colorado's SIP also must contain additional Reasonable Progress emission control requirements for other large sources identified by the state as impairing visibility in Class I areas. As with BART, Reasonable Progress requirements must be established based on consideration of specified factors set forth under federal law. Finally, the Regional Haze SIP must include extensive and exacting technical documentation describing, among other things, Colorado's visibility monitoring strategy, the sources of visibility impairment in Colorado, how Colorado established BART and Reasonable Progress requirements in accordance with federal law, and Colorado's long term strategy to achieve ongoing visibility improvement at each of Colorado's Class I areas.

The revisions that the Commission adopted represent a comprehensive Regional Haze SIP that addresses each of these required elements. These revisions include changes to AQCC Regulations No. 3 and No. 7, as well as the adoption of a new Regional Haze State Implementation Document, which sets forth the technical support information demonstrating that

1 BART sources in Colorado are listed in Attachment 1 to this report.

Colorado has complied with federal requirements for establishing a Regional Haze Program.

The revisions to AQCC Regulation No. 3 contain the new BART, BART Alternative, and Reasonable Progress requirements for Colorado sources. These control requirements, and the anticipated emission reductions that will be achieved from these requirements are set forth in Attachment 2 to this report. The revisions to AQCC Regulation No. 3 also include monitoring, recordkeeping and reporting requirements for the various BART, BART Alternative and Reasonable Progress sources necessary to ensure compliance with the established emission reduction requirements. Finally, the Regulation No. 3 revisions include a number of technical changes that are necessary to conform the Regulation to federal Regional Haze Program Requirements. With the exception of the revisions involving certain Public Service Company of Colorado sources discussed below, the revisions to Regulation No. 3 were ultimately agreed to by all of the parties to the Commission's Regional Haze Rulemaking including the subject industry sources. In total, the new Regulation No. 3 requirements are expected to reduce Nitrogen Oxide (NO_x) and Sulfur Dioxide (SO_2) emissions by approximately 34,700 tons per year and 35,700 tons per year respectively.

Included within the revisions to AQCC Regulation No. 3, is a BART Alternative for various sources owned by Public Service Company of Colorado (PSCo) that was developed in accordance with the procedures set forth in HB10-1365, the Clean Air Clean Jobs Act (CACJA), which the General Assembly adopted and the Governor signed during the 2010 legislative session. See § 40-3.2-208, C.R.S. As required under CACJA, the Public Utilities Commission (PUC) conducted an eight month long process aimed at developing a comprehensive emission reduction plan for PSCo's BART and Reasonable Progress sources. This process included the participation of dozens of parties with varying interests ranging from coal producing interests, to natural gas producers, to environmental groups and interested local governments. At the conclusion of the PUC process, the PUC issued an Order on December 15, 2010, detailing emission control requirements for PSCo's sources. This Order set forth a mix of control requirements, including the shutdown of older and less efficient coal fired electric generating units, the conversion of certain units to natural gas operation, and requirements for the most advanced add-on NO_x and SO_2 pollution controls for PSCo's largest coal burning units.

In accordance with the procedures set forth in CACJA, the AQCC incorporated all of these requirements into the Regional Haze SIP as the Bart Alternative for the subject PSCo sources.[2] During the hearing on the PSCo BART Alternative plan, the Air Pollution Control Division, PSCo, various environmental groups, Denver and Boulder Counties, and numerous public

2 In addition to the process involving PSCo's sources, the PUC conducted a separate process required under CAJCA to develop control requirements for Black Hills Corporation's Clark Station. Clark Station consists of two very small, older coal fired electric generating units. At the conclusion of this process, the PUC approved Black Hills plan to retire the Clark Station units. The AQCC incorporated the requirement for retirement of the Clark Station units as the Reasonable Progress requirements for these units as contemplated under CACJA. The AQCC adopted these requirements without any objection from the source, the participating environmental groups or the coal interests that participated in the AQCC hearing.

commenters, including natural gas companies, provided testimony in support of the plan. The Colorado Mining Association, Peabody Energy Corporation and the Associated Governments of Northwest Colorado asked that the AQCC either reject or delay consideration on the PSCo BART Alternative, but did not offer any alternative proposal for the PSCo sources covered by the BART Alternative.

The revisions to Regulation No. 7 that the Commission adopted do not establish any new emission control requirements for Colorado. Rather, these revisions incorporate existing state-only control requirements for reciprocating internal combustion engines (RICE) into the Regional Haze SIP. By incorporating these requirements into the SIP, Colorado can take credit for the emission reductions as Reasonable Progress requirements in meeting its regional haze obligations without imposing any additional costs on Colorado sources. None of the parties to the Commission Regional Haze Rulemaking opposed the revisions to Regulation No. 7

Finally, the Commission's revisions to the Regional Haze SIP Document set forth the remaining elements required to establish an approvable Regional Haze SIP. These include the following: 1) an overview of Colorado's Regional Haze Program; 2) Colorado's response to comments from Federal Land Managers on the program as required by federal law; 3) a description of the state's monitoring strategy and visibility modeling work; 4) identification of the sources of visibility impairment at Colorado's Class I areas; 5) a detailed description of all of the BART, BART Alternative and Reasonable Progress determinations, and demonstrations that the process used to reach these determinations complied with federal law; and finally 6) Colorado's long term strategy to achieve ongoing visibility improvement at each of Colorado's Class I areas.

CONCLUSION

Ultimately, the Regional Haze SIP adopted by the Commission represents a comprehensive, highly technical planning document designed to meet the elaborate and exacting federal requirements governing the Regional Haze Program. As adopted, the plan will reduce the emission of approximately 71,000 tons of visibility impairing pollutants in Colorado every year. Additionally, the reduction of approximately 35,000 tons of NO_x emissions will be essential to Colorado's efforts to achieve or maintain National Ambient Air Quality Standards for ground level ozone in areas throughout the state. These SIP revisions were adopted only after an unprecedented level of public process before the PUC and the Air Quality Control Commission.

As adopted, the SIP revisions taken in their entirety will allow Colorado to submit a timely and approvable Regional Haze SIP to EPA. In submitting this SIP to EPA, Colorado will meet its obligations under the federal Clean Air Act and avoid imposition of an EPA developed Federal Implementation Plan, while both improving the scenic vistas in Colorado's most important national parks and wilderness areas and protecting the health of Colorado's citizens.

ATTACHMENT 3
Section 25-7-133 (1) and (2), C.R.S.

25-7-133. Legislative review and approval of state implementation plans and rules - legislative declaration. (1) Notwithstanding any other provision of law but subject to subsection (7) of this section, by January 15 of each year the commission shall certify in a report to the chairperson of the legislative council in summary form any additions or changes to elements of the state implementation plan adopted during the prior year that are to be submitted to the administrator for purposes of federal enforceability. Such report shall be written in plain, nontechnical language using words with common and everyday meaning that are understandable to the average reader. Copies of such report shall be available to the public and shall be made available to each member of the general assembly. The provisions of this section shall not apply to control measures and strategies that have been adopted and implemented by the enacting jurisdiction of a local unit of government if such measures and strategies do not result in mandatory direct costs upon any entity other than the enacting jurisdiction.

(2) (a) By the February 15 following submission of the certified report under subsection (1) of this section, any member of the general assembly may make a request in writing to the chairperson of the legislative council that the legislative council hold a hearing or hearings to review any addition or change to elements of the SIP contained in the report submitted pursuant to subsection (1) of this section. Upon receipt of such request, the chairperson of the legislative council shall forthwith schedule a hearing to conduct such review. Any review by the legislative council shall determine whether the addition or change to the SIP element accomplishes the results intended by enactment of the statutory provisions under which the addition or change to the SIP element was adopted. The legislative council, after allowing a public hearing preceded by adequate notice to the public and the commission, may recommend the introduction of a bill or bills based on the results of such review. If the legislative council does not recommend introduction of a bill under this subsection (2), the addition or change to the SIP element may be submitted under paragraph (b) of this subsection (2). Any bill recommended for consideration under this subsection (2) shall not be counted against the number of bills to which members of the general assembly are limited by law or joint rule of the senate and the house of representatives. If the legislative council does not recommend the introduction of a bill under this paragraph (a), and the member or members of the general assembly that requested such review will be introducing a bill under the provisions of paragraph (c) of this subsection (2), any such member shall provide written notice to the chairperson of the legislative council within three days after the action by the legislative council not to recommend introduction of a bill. If such member or members provide such written notice, the addition or change to the SIP or any element thereof that is the subject of any such bill may not be submitted to the administrator of the federal environmental protection agency until the expiration of the addition or change to the SIP has been postponed by the general assembly acting by bill or the member or members provide written notice to the chairperson of the executive committee of the legislative council that no bill will be introduced.

(b) Unless a written request for legislative council review of an addition or change to a SIP element is submitted by the February 15 following submission of the report under subsection (1) of this section, or a notice is provided by a member or members that they are introducing a bill under paragraph (c) of this subsection (2) within three days after legislative council action not to introduce a bill under paragraph (a) of this subsection (2), all other additions or changes to a SIP element described in such report shall be submitted to the administrator for final approval and incorporation

into the SIP.

(c) Until such February 15 as provided in paragraph (b) of this subsection (2), the commission may only submit an addition or change to the SIP or any element thereof, as defined in section 110 of the federal act, any rule which is a part thereof, or any revision thereto as specified in subsection (1) of this section to the administrator for conditional approval or temporary approval. If legislative council review is requested as to any addition or change to a SIP element under paragraph (a) of this subsection (2), then no such SIP, revision, rule required by the SIP or revision, or rule related to the implementation of the SIP or revision so submitted to the administrator may take effect for purposes of federal enforceability, or enforcement of any kind at the state level against any person or entity based only on the commission's general authority to adopt a SIP under section 25-7-105 (1), unless expiration of the SIP, rule required for the SIP, or addition or change to a SIP element has been postponed by the general assembly acting by bill in the same manner as provided in section 24-4-103 (8) (c) and (8) (d), C.R.S. Any member of the general assembly may introduce a bill to modify or delete all or a portion of the SIP or any rule or additions or changes to SIP elements which are a component thereof. Any bill introduced under this paragraph (c) shall not be counted against the number of bills to which members of the general assembly are limited by law or joint rule of the senate and the house of representatives. Any committee of reference of the senate or the house of representatives to which a bill introduced under this paragraph (c) is referred shall conduct as part of consideration of any such bill on the merits the review provided for under paragraph (a) of this subsection (2). If any bill is introduced under paragraph (a) of this subsection (2) or under this paragraph (c) to postpone the expiration of any addition or change to a SIP element described in a report submitted under subsection (1) of this section or paragraph (d) of this subsection (2), and any such bill does not become law, the addition or change to a SIP element addressed in such bill may be submitted to the administrator of the federal environmental protection agency for final approval and incorporation into the SIP under paragraph (b) of this subsection (2).

ATTACHMENT 4

State Representative
JAMES E. KERR
6359 S. Chase Court
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Chairman:
State, Veterans & Military Affairs Committee
Member:
Health & Environment Committee
Legislative Audit Committee
Legislative Council Committee

COLORADO

HOUSE OF REPRESENTATIVES

STATE CAPITOL

DENVER

80203

February 11, 2001

Honorable Brandon Shaffer
Chairman, Legislative Council
State Capitol
200 East Colfax
Denver, Colorado 80202

Dear Senator Shaffer:

Pursuant to the provisions of §25-7-133 C.R.S., we hereby request that the Legislative Council hold a hearing to review recent changes to the State Implementation Plan (SIP) which were submitted to Legislative Council on January 14, 2011. The SIP was approved by the Colorado Air Quality Control Commission (AQCC) on January 7, 2011. A significant portion of the SIP is based upon an emission reduction plan (Plan) prepared by Public Service Company of Colorado (PSCo) pursuant to the Clean Air-Clean Jobs Act (CACJA).

The PSCo Plan was not finalized by the Public Utilities Commission (PUC) and available for public, or AQCC, review until December 15, 2010. This left just a mere three weeks, which included the Christmas and New Year holidays, for the public to review and comment on a Plan of significant consequence to the State of Colorado prior to it being considered by the AQCC at the January 7th hearing. With the rushed consideration of the Plan, serious concerns and questions exist as to whether the Plan was designed and approved in accordance with state law. For instance, the AQCC is required to provide the public with at least 60-days notice before conducting a SIP rulemaking. § 25-7-110(1) C.R.S. The notice of rulemaking that the AQCC released to the public 60-days before the January 7th hearing did not include the Plan approved by the PUC on December 15, 2011 (a mere 23-days before the AQCC hearing).

Other serious concerns exist as to whether the AQCC, and the Colorado Department of Public Health and Environment (CDPHE), conducted their analysis of the Plan in accordance with their duties under the Colorado Administrative Procedures Act (APA). The CACJA required the CDPHE to make substantive determinations about the Plan that were never opened to the public for review and comment, as required under the APA. There is also concern that the SIP includes requirements that are more stringent than what is currently required under the federal Clean Air Act, something that is specifically prohibited under §25-7-105.1(1) C.R.S.

These are just two of the many examples we are aware of that indicate that the SIP may not conform to the State's Clean Air Act as set forth in Title 25, Article 7 C.R.S. Additionally, there are questions and concerns about the Plan's costs to consumers, and its impact on energy producing communities in Northwest Colorado.

These questions raise significant questions in our minds as to whether the new SIP elements meet the requirements under the State's Clean Air Act and if they accomplish the requirements of the CACJA. For the reasons stated above, we therefore request that you forthwith schedule a hearing on the SIP changes so that these matters can be examined in more detail.

Sincerely,

Jim Kerr

Jim Kerr
State Representative
House District 28

Marsha Looper

S. G. Sonnenberg

Shaun Mitchell

Lois Tochtrop

SENATE
STATE OF COLORADO
DENVER

February 14, 2011

Honorable Brandon Shaffer
Chairman, Legislative Council
State Capitol
200 E. Colfax Avenue
Denver, CO 80203

Dear Senator Shaffer:

Pursuant to the provisions of §25-7-133 C.R.S., we hereby request that the Legislative Council hold a hearing to review recent changes to the State Implementation Plan (SIP) which were submitted on January 14, 2011. The Colorado Air Quality Control Commission approved the SIP based largely on the emission reduction plan prepared by the Public Service Company as a part of HB 10-1365.

We have serious concerns about the extent to which the State Implementation Plan meets the emission reduction standards set out in HB 10-1365. The abbreviated timeline for analysis and review of the Public Service Company's emission reduction plan, particularly in light of significant last-minute changes to the plan, lead us to believe that further review of the SIP is necessary.

For that reason we request that the Legislative Council hold a public hearing on the SIP to give the General Assembly and the public more time to thoroughly review this momentous plan and its impact on Colorado.

Sincerely,

Scott Renfroe
State Senator

Kevin Lundberg
State Senator

Shawn Mitchell
State Senator

Keith King
State Senator

Jean White
State Senator

Ted Harvey
State Senator

Mark Scheffel
State Senator

Kent Lambert
State Senator

ATTACHMENT 5
House Bill 10-1365

40-3.2-201. Short title. This part 2 shall be known and may be cited as the "Clean Air - Clean Jobs Act".

40-3.2-202. Legislative declaration. (1) The general assembly hereby finds, determines, and declares that the federal "Clean Air Act", 42 U.S.C. sec. 7401 et seq., will likely require reductions in emissions from coal-fired power plants operated by rate-regulated utilities in Colorado. A coordinated plan of emission reductions from these coal-fired power plants will enable Colorado rate-regulated utilities to meet the requirements of the federal act and protect public health and the environment at a lower cost than a piecemeal approach. A coordinated plan of reduction of emissions for Colorado's rate-regulated utilities will also result in reductions in many air pollutants and promote the use of natural gas and other low-emitting resources to meet Colorado's electricity needs, which will in turn promote development of Colorado's economy and industry.

(2) The general assembly further finds that the use of natural gas to reduce coal-fired emissions may require rate-regulated utilities to enter into long-term contracts for natural gas in a manner that protects electricity consumers. Even though such long-term contracts might be beneficial to consumers, financial rating agencies could find that such long-term contracts increase the financial risk to rate-regulated utilities, which in turn could increase the cost of capital to these utilities. The general assembly finds that it is important to give financial markets confidence that utilities will be able to recover the costs of long-term gas contracts without the risk of future regulators disallowing contracts.

(3) 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 this part 2. In order to allow these utilities to continue to provide reliable electric service, alter their operations in the manner described by this part 2, and meet other state public policy goals, it is imperative that Colorado rate-regulated utilities continue in sound financial condition and remain attractive investments so that sufficient capital is provided to achieve the state's goals. 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. 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.

40-3.2-203. Definitions. As used in this part 2, unless the context otherwise requires:

(1) "Air quality control commission" means the commission created in section 25-7-104, C.R.S.

(2) "Department" means the department of public health and environment.

(3) "Federal act" means the federal "Clean Air Act", 42 U.S.C. sec. 7401 et seq., as amended.

(4) "State act" means the "Colorado Air Pollution Prevention and Control Act", article 7 of title 25, C.R.S.

(5) "State implementation plan" means the plan required by and described in section 110 (a) and other provisions of the federal act.

40-3.2-204. Emission control plans - role of the department of public health and environment - timing of emission reductions - approval. (1) On or before August 15, 2010, and in coordination with current or expected requirements of the federal act and the state act, all

rate-regulated utilities that own or operate coal-fired electric generating units located in Colorado shall submit to the commission an emission reduction plan for emissions from those units.

(2) (a) The plan filed under this section shall cover a minimum of nine hundred megawatts or fifty percent of the utility's coal-fired electric generating units in Colorado, whichever is smaller. Except as set forth in section 40-3.2-206, the coal-fired capacity covered under the plan filed under this section shall not include any coal-fired capacity that the utility has already announced that it plans to retire prior to January 1, 2015. At the utility's discretion, the plan may include some or all of the following elements:

(I) New emission control equipment for oxides of nitrogen and other pollutants;

(II) Retirement of coal-fired units, if the retired coal-fired units are replaced by natural gas-fired electric generation or other low-emitting resources as defined in section 40-3.2-206, including energy efficiency;

(III) Conversion of coal-fired generation to run on natural gas;

(IV) Long-term fuel supply agreements;

(V) New natural gas pipelines and other supporting gas infrastructure;

(VI) Increased utilization of existing gas-fired generating capacity;

(VII) New transmission lines and other supporting transmission infrastructure;

(VIII) Emission control equipment that is required to be installed at affected units prior to or in conjunction with any retirement, conversion, or emission control equipment retrofit set forth under the plan in order to limit any pollutant other than oxides of nitrogen; and

(IX) Any other capital, fuel, and operations and maintenance expenditures appropriate to support the implementation of the plan.

(b) (I) Prior to filing the plan, the utility shall consult with the department and shall work with the department in good faith to design a plan to meet the current and reasonably foreseeable requirements of the federal act and state law in a cost-effective and flexible manner.

(II) The commission shall provide the department an opportunity to:

(A) Comment on the air quality, all other air pollutants, and other emission reductions of the plan; and

(B) Evaluate and determine whether the plan is consistent with the current and reasonably foreseeable requirements of the federal act.

(III) In commenting upon the utility's plan, the department shall 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.

(IV) The commission shall not approve a plan except after an evidentiary hearing and unless the department has determined that the plan is consistent with the current and reasonably foreseeable requirements of the federal act.

(c) The plan shall include a schedule that would result in full implementation of the plan on or before December 31, 2017. The schedule may include interim milestones. The utility shall design the schedule to protect system reliability, control overall cost, and assure consistency with the requirements of the federal act.

(d) The plan shall set forth the costs associated with activities identified in the plan, including the planning, development, construction, and operation of elements identified pursuant to subparagraphs (I) to (IX) of paragraph (a) of this subsection (2), as well as the costs of any

shutdown, decommissioning, or repowering of existing coal-fired electric generating units that are set forth in the plan.

40-3.2-205. Review - approval. (1) In evaluating the plan, the commission shall consider the following factors:

(a) Whether the department 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 as necessary to comply with current and reasonably foreseeable requirements of the federal act and the state act. The reduction in emissions under this paragraph (a) shall be measured from 2008 levels at coal-fired power plants identified in the plan. In determining the reduction in emissions under this paragraph (a), the department shall include:

(I) Emissions from coal-fired power plants identified in the plan and continuing to operate after retrofit with emission control equipment; and

(II) Emissions from any facilities constructed to replace any retired coal-fired power plants identified in the plan.

(b) Whether the department has made the determination under section 40-3.2-204 (2) (b) (III);

(c) The degree to which the plan will result in reductions in other air pollutant emissions;

(d) The degree to which the plan will increase utilization of existing natural gas-fired generating capacity;

(e) 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;

(f) Whether the plan promotes Colorado economic development;

(g) Whether the plan preserves reliable electric service for Colorado consumers;

(h) Whether the plan is likely to help protect Colorado customers from future cost increases, including costs associated with reasonably foreseeable emission reduction requirements; and

(i) Whether the cost of the plan results in reasonable rate impacts. In evaluating the rate impacts of the plan, the commission shall examine the impact of the rates on low-income customers.

(2) The commission shall review the plan and enter an order approving, denying, or modifying the plan by December 15, 2010. Any modifications required by the commission shall result in a plan that the department determines is likely to meet current and reasonably foreseeable federal and state clean air act requirements.

(3) All 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.

(4) If the utility disagrees with the commission's modifications to its proposed plan with respect to resource selection, the utility may withdraw its application.

40-3.2-206. Coal plant retirements - replacement resources. (1) (a) The general assembly finds that, in designing a coordinated emission reduction plan as described in section 40-3.2-204 and to expeditiously accelerate coal plant retirements, it is in the public interest for utilities to give primary consideration to replacing or repowering their coal generation with natural gas generation and that utilities shall also consider other low-emitting resources, including energy efficiency, if this replacement or repowering can be accomplished prudently and for reasonable rate impacts compared with placing additional emission controls on coal-fired generating units, and if electric system reliability can be preserved. To that end, in the plan required under section 40-3.2-204, each utility shall include an evaluation of the following proposals:

(I) The cost and system reliability impacts of retiring a minimum of nine hundred megawatts

of coal-fired electric generating capacity, or fifty percent of the utility's coal-fired generating units in Colorado, whichever is less, by January 1, 2015, and repowering the affected coal-fired facilities with natural gas or replacing them with natural gas-fired generation or other low-emitting resources, including energy efficiency. The coal-fired capacity evaluated under this subparagraph (I) shall not include any coal-fired capacity that the utility has already announced that it plans to retire prior to January 1, 2015. The utility may also prepare evaluations of additional scenarios, including scenarios that result in the retirement of less than nine hundred megawatts of coal-fired electric generating capacity or the retirement of some portion of the nine hundred megawatts of capacity after January 1, 2015, but before January 1, 2018.

(II) Retirements of a portion of its coal-fired generating capacity in the period after April 19, 2010, but prior to January 1, 2015. At a minimum, the utility shall evaluate whether to retire a portion of its coal-fired capacity on or before January 1, 2013, or whether the retirements of coal-fired generating facilities that have already been announced could be advanced to an earlier retirement date.

(b) (I) For all evaluations required by this subsection (1), the utility shall report:

(A) The estimated overall impacts on the utility's emissions of oxides of nitrogen and other pollutants;

(B) The feasibility of the retirement, repowering, or replacement on the schedule proposed in the evaluation;

(C) The costs and impact on electric rates from these proposals; and

(D) The impact of the retirements on the reliability of the utility's electric service.

(II) All evaluations required by this subsection (1) shall contrast the costs of replacing coal generation with natural gas generation and other low-emitting resources, including energy efficiency, with the costs of installing additional emission controls on the coal plants.

(2) The utility shall set forth in its plan the utility's proposal for the best way of timely meeting the emission reduction requirements required by federal and state law, given the need to preserve electric system reliability, to avoid unreasonable rate increases, and the economic and environmental benefits of coordinated emission reductions.

(3) In reviewing the reasonableness of the utility's proposed plan, the commission shall:

(a) 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;

(b) Use reasonable projections of future coal and natural gas costs;

(c) Incorporate a reasonable estimate for the cost of reasonably foreseeable emission regulation consistent with the commission's existing practice;

(d) Consider the degree to which the plan will increase utilization of existing natural gas-fired generating resources available to the utility, together with increased utilization of other low-emitting resources including energy efficiency; and

(e) Consider the economic and environmental benefits of a coordinated emissions reduction strategy.

(4) The utility may enter into long-term gas supply agreements to implement the requirements of this part 2. 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.

40-3.2-207. Cost recovery - legislative declaration. (1) (a) A utility 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.

(b) The general assembly finds that the emissions reductions under this part 2 are being made to assist the state of Colorado to comply with current and reasonably foreseeable emission restrictions under federal law. To provide this assistance, the utility is being asked to make substantial capital investments and to enter into substantial contractual commitments in an expedited time period outside of the normal resource planning process.

(2) (a) If a public utility's wholesale sales are subject to regulation by the federal energy regulatory commission, and if the public utility sells power on the wholesale market from a project developed pursuant to the plan, the commission shall determine whether to assign a portion of the plan cost to be recovered from the public utility's wholesale customers. The commission may make such assignment to the extent that it does not conflict with the public utility's wholesale contracts entered into before April 19, 2010.

(b) Except as specified in paragraph (c) of this subsection (2), if the commission makes an assignment of costs pursuant to paragraph (a) of this subsection (2) and if the utility applies to the federal energy regulatory commission for recovery and pursues that application in good faith, then:

(I) To the extent that the federal energy regulatory commission does not permit recovery of the allocated wholesale portion of plan-related investment, the commission shall approve retail rates sufficient to recover such disallowed wholesale portion of the investment through the recovery mechanism detailed in this section; and

(II) The public utility may not recover any revenue shortfall caused by a delay in making any filing with the federal energy regulatory commission or due to any rate suspension period employed by the federal energy regulatory commission or because the public utility failed to pursue recovery of the amounts at the federal energy regulatory commission in good faith.

(c) If the public utility fails to apply to the federal energy regulatory commission within six months after the commission's final order assigning a portion of the plan's costs to the public utility's wholesale customers, the public utility is not entitled to recover the assigned portion of the costs from its retail customers.

(3) Current recovery shall be allowed on construction work in progress at the utility's weighted average cost of capital, including its most recently authorized rate of return on equity, for expenditures on projects associated with the plan during the construction, startup, and preservice implementation phases of the projects.

(4) To the extent that an approved plan includes the early conversion or closure of coal-based generation capacity by January 1, 2015, and to the extent that the utility demonstrates that a lag in the 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, the commission shall employ rate-making mechanisms, in addition to allowing a current return on construction work in progress, that permit rate adjustments, no less frequently than once per year, without requiring the utility to file a general

rate case to allow recovery of the approved plan's costs. Such rate-making mechanisms may include a separate rate adjustment clause, regular make-whole rate increases, or other appropriate mechanisms as determined by the commission.

(5) 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.

(6) 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 filed under this part 2.

40-3.2-208. Air quality planning. (1) The air quality provisions of the emission reduction plan filed under this part 2 are intended to fulfill the requirements of the state and federal acts and shall be proposed by the department to the air quality control commission after the utility files the plan with the commission to be considered for incorporation into the regional haze element of the state implementation plan.

(2) (a) Upon the utility's filing of the utility plan with the commission pursuant to section 40-3.2-204, the air quality control commission, in response to the proposal by the department, shall initiate a proceeding to incorporate the air quality provisions of the utility plan into the regional haze element of the state implementation plan. Except as set forth in this subsection (2), the air quality control commission shall not act on the utility plan or the provisions of the regional haze element of the state implementation plan that would establish controls for those units covered by the utility plan until after the commission's approval of the utility plan.

(b) The air quality control commission shall vacate the entire proceeding related to the utility plan and shall initiate a new proceeding for the consideration of alternative proposals for the appropriate controls for those units covered by the utility plan for inclusion in the regional haze element of the state implementation plan if:

(I) The commission does not approve the utility plan by December 15, 2010;

(II) The utility withdraws its application pursuant to section 40-3.2-205 (4); or

(III) The air quality control commission rejects any portion of the utility plan as approved by the commission.

(c) The air quality control commission shall conduct the proceedings specified in this subsection (2) after public notice and an opportunity for the public to participate in accordance with the air quality control commission's procedures.

(3) If the final approved provisions of the state implementation plan are not consistent with the air quality provisions of the utility plan, the utility may file a revised utility plan with the commission that modifies the original plan to be consistent with the final approved state implementation plan. The revised utility plan is subject to all of the review and cost recovery provisions contained in this part 2. Notwithstanding any revision required to the utility plan, the utility is entitled to fully recover any costs it prudently incurred or contracted to incur under the originally approved plan prior to the plan's revision and any costs incurred as a result of any enforceable state implementation plan or other air quality requirements.

40-3.2-209. Early reductions. Reductions in emissions achieved pursuant to this part 2 through a compliance strategy before such reductions are mandated under federal law are voluntary for purposes of determining early reduction credits under federal law.

40-3.2-210. Exemption from limits on voluntary emission reductions. The limits on utility expenditures on voluntary emission reductions in section 40-3.2-102 do not apply to utility expenditures under a plan approved by the commission under this part 2.

ATTACHMENT 6

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 3

STATIONARY SOURCE PERMITTING AND AIR POLLUTANT EMISSION NOTICE REQUIREMENTS

5 CCR 1001-5

Outline of Regulation

Regulation Number 3

Style Guide

Many provisions of this Regulation Number 3 have been approved by the U.S. EPA for incorporation into Colorado's State Implementation Plan (SIP). Some provisions are currently under review by the U.S. EPA. The following guide to the font styles used in this Regulation Number 3 can be used to identify those provisions that have been adopted by the Air Quality Control Commission and are currently under review by the U.S. EPA.

* *Italicized text* will become effective when the U.S. EPA approves that language for incorporation into the state implementation plan

* Underlined text will be effective until the U.S. EPA approves the italicized text for incorporation into the state implementation plan

PART A CONCERNING GENERAL PROVISIONS APPLICABLE TO REPORTING AND PERMITTING

I. Applicability

I.A. The provisions of this Part A shall apply statewide to all sources of air pollutants except as otherwise provided herein.

VI. Regional Haze Determinations

VI.A. BART Determinations

VI. A.1. The provisions of this Section VI.A of Regulation Number 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.A.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits:

BART Determinations for Colorado Sources			
Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
CENC Unit 4	0.37 lb/MMBtu (30-day rolling average) or 0.26 lb/MMBtu Combined Average for Units 4 and 5 (30-day rolling average)	1.0 lb/MMBtu (30-day rolling average)	0.07 lb/MMBtu
CENC Unit 5	0.19 lb/MMBtu (30-day rolling average) or 0.26 lb/MMBtu Combined Average for Units 4 and 5 (30-day rolling average)	1.0lb/MMBtu (30-day rolling average)	0.07 lb/MMBtu
Craig Unit 1	0.28 lb/MMBtu (30-day rolling average)	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Craig Unit 2	0.08 lb/MMBtu (30-day rolling average)*	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu

* The NOx emission limits for Craig Units 1 and 2 constitute a BART Alternative.

Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**

Comanche Unit 1	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	0.12 lb/MMBtu (individual unit 30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	0.03 lb/MMBtu
Comanche Unit 2	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	0.12 lb/MMBtu (individual unit 30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	0.03 lb/MMBtu
Hayden Unit 1	0.08lb/MMBtu (30-day rolling average)	0.13 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Hayden Unit 2	0.07 lb/MMBtu (30-day rolling average)	0.13 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 5	0.31 lb/MMBtu (30-day rolling average)	0.26 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 6	0.31lb/MMBtu (30-day rolling average)	0.13lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 7	0.29 lb/MMBtu (30-day rolling average)	0.13lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu

CEMEX – Lyons Kiln	255.3 lbs/hr (30-day rolling average) 901.0 tons/year (12-month rolling average)	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	0.275 lb/ton of dry feed 20% opacity
CEMEX – Lyons Dryer	13.9 tons/yr	36.7 tons/yr	22.8 tons/yr 10% opacity

VI.A.3. Each source listed in the above tables must comply with the above limits and averaging times as expeditiously as practicable, but in no event later than five years after EPA approval of Colorado's state implementation plan for regional haze, or relevant component thereof. Each source listed in the above tables must maintain control equipment or operational practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained.

VI.A.4. The sources shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the BART portion of the Regional Haze SIP. The Division shall publish these proposed schedules and provide for a thirty-day public comment period following publication. The Division shall publish its final determinations regarding the proposed schedules for compliance within sixty days after the close of the public comment period and will respond to all public comments received.

VI.B. Reasonable Progress Determinations

VI.B.1. The provisions of this Section VI.B of Regulation Number 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.B.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits:

RP Determinations for Colorado Sources			
Emission Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
Rawhide Unit 101	0.145 lb/MMBtu (30-day rolling average)	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
CENC Unit 3	246 tons per year (12-month rolling total)	1.2 lb/MMBtu	0.07 lb/MMBtu

practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained.

VI.B.4. The sources shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the RP portion of the Regional Haze SIP. The Division shall publish these proposed schedules and provide for a thirty-day public comment period following publication. The Division shall publish its final determinations regarding the proposed schedules for compliance within sixty days after the close of the public comment period and will respond to all public comments received.

VI.C. Public Service Company of Colorado (PSCo) BART Alternative Program

VI.C.1. The provisions of this Section VI.C of Regulation Number 3, Part F (with the exception of the SO2 cap of subsection VI.C.4) shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.C.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits, after the following compliance dates:

BART Alternative Program Determinations for PSCo Sources			
Emission Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
Cherokee * Unit 1 Shutdown No later than 7/1/2012	0 Shutdown No later than 7/1/2012	0 Shutdown No later than 7/1/2012	0 Shutdown No later than 7/1/2012
Cherokee Unit 2 Shutdown 12/31/2011	0 Shutdown 12/31/2011	0 Shutdown 12/31/2011	0 Shutdown 12/31/2011
Cherokee Unit 3 Shutdown No later than 12/31/2016	0 Shutdown No later than 12/31/2016	0 Shutdown No later than 12/31/2016	0 Shutdown No later than 12/31/2016

Cherokee Unit 4	0.12 lb/MMBTU (30-day rolling average) by 12/31/2017 Natural Gas Operation 12/31/2017	7.81 tpy (rolling 12 month average) Natural Gas Operation 12/31/2017	0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5 Shutdown 12/31/2017	0 Shutdown 12/31/2017	0 Shutdown 12/31/2017	0 Shutdown 12/31/2017
Pawnee	0.07 lb/MMBTU (30-day rolling average) by 12/31/2014	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	0.03 lbs/MMBtu
Arapahoe** Unit 3 Shutdown 12/31/2013	0 Shutdown 12/31/2013	0 Shutdown 12/31/2013	0 Shutdown 12/31/2013
Arapahoe Unit 4	600 tpy on (rolling 12 month average) Natural Gas operation12/31/2014	1.28 tpy (rolling 12 month average) Natural Gas operation 12/31/2014	0.03 lbs/MMBtu Natural Gas operation 12/31/2014

* 500 tpy NOx will be reserved from Cherokee Station for netting or offsets

** 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation

VI.C.3. Each source listed in the above table must either shut down or comply with the above limits and averaging times no later than the compliance date set forth in the above table. Each source listed in the above table must maintain any applicable control equipment required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment is properly operated and maintained.

VI.C.4. In addition to the above listed emission limits and compliance dates, between 1/1/2013 and 12/31/2015, Cherokee Units 3 and 4 and Valmont, considered as a whole, shall not emit in excess of 4,200 tons of SO2 per year as determined on a calendar year annual basis. Between 1/1/2016 and 12/31/2017 Cherokee Unit 4 and Valmont considered as a whole, shall not emit in excess of 3,450 tons of SO2 per year as determined on a calendar year annual basis.

VII. Monitoring, Recordkeeping, and Reporting for Regional Haze Limits

- Add new definition of Subject to Regulation consistent with EPA's GHG Tailoring Rule and include the rescission clause as discussed above (Section I.B.44.)

- Revise annual emission fees to exclude GHGs (Section VI.D.)

Part B

- Revise general permitting requirements to authorize the Division to issue synthetic minor permits for GHGs where stationary sources voluntarily choose to seek federally enforceable limits for GHG if they would otherwise be subject to PSD or Title V Permitting Programs (Sections II.A.4., II.A.7.)

Part C

- Clarify that complete Title V Operating Permit applications include the reporting of GHG emissions as they are pollutants which may be subject to requirements applicable to the source, but not air pollutants, under Regulation 3 definitions (Section III.C.3.a.).

Part D

- Revise the Definitions (Section II.A.):

- Revise BACT, Major Modification and Major Stationary Source Definition to use the term Regulated NSR Pollutant for consistency and remove italics consistent with EPA's GHG Tailoring Rule so that these definitions become effective by January 2, 2011 (Sections II.A.8., II.A.22., II.A.24.a., II.A.24.a.(ii) and II.A.24.b.)

- Revise Regulated NSR Pollutant definition and remove italics consistent with EPA's GHG Tailoring Rule so that it becomes effective by January 2, 2011 (Section II.A.38.)

Additionally, the Commission approves typographical, grammatical and formatting changes, as necessary.

I.UU. Adopted January 7, 2011

Regulation Number 3, Part D (Concerning Major Stationary Source New Source Review and Prevention of Significant Deterioration) and Part F (Best Available Retrofit Technology (BART) and Reasonable Progress for Regional Haze)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S, and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

Specific Statutory Authority

The Colorado Air Quality Control Commission (Commission) promulgates this regulation pursuant to the authority granted under Colorado Revised Statutes, Sections 25-7-105(1)(c), (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 40-3.2-208 (authority to incorporate emission reduction plans for rate-regulated utilities within the state's Regional Haze State Implementation Plan).

Basis and Purpose

PART D

These revisions to Regulation Number 3, Part D change the review and revision period for the Regional Haze Long Term Strategy (LTS) from every three years to every five years. This change aligns the reporting periods for the Regional Haze LTS and the Regional Haze progress reports that are required every five years pursuant to 40 C.F.R. Section 51.308(g).

PART F

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) promulgated the final Regional Haze Rule (Rule), which went into effect, on August 30, 1999, and which requires each state to submit a State Implementation Plan (SIP) to address regional haze. The Rule is intended to achieve the national visibility goals as expressed in Section 169(a) of the Clean Air Act, 42 U.S.C. Section 7491. Colorado must develop a SIP revision in coordination and consultation with other states, tribes, federal land managers, EPA and Regional Planning Organizations (RPOs) designated by EPA. In the west, the RPO is the Western Regional Air Partnership (WRAP).

Regional Haze is a visibility impairment that is caused by multiple sources over a broad geographic region. EPA's Regional Haze Rule requires every state to submit a SIP designed to improve visibility in its mandatory Class I federal areas (Class I areas). Class I areas are areas of great scenic importance, such as national parks and wilderness areas. There are 12 Class I areas in Colorado, and 156 nationwide.

A key element of EPA's regional haze program is Best Available Retrofit Technology (BART) for certain emission sources. Section 169A(b)(2)(A) of the Clean Air Act requires BART for certain existing major facilities, placed into operation between August 7, 1962 and August 7, 1977, that have the potential to emit more than 250 tons of visibility-reducing pollution a year. EPA's Regional Haze Rule requires SIPs to include BART emission limits for each subject-to-BART source that may reasonably be anticipated to impair visibility in any Class I area, unless the state demonstrates that an emissions trading program or other alternative measures will achieve greater reasonable progress toward natural visibility conditions. See 40 CFR Part 51 Section 308(e). EPA promulgated a BART Rule separate from its Regional Haze Rule. EPA's BART Rule includes guidelines (Appendix Y) regarding how states should make BART determinations. See 70 Fed. Reg. 39104 (July 6, 2005). EPA also promulgated a "BART Alternative" Rule. See 71 Fed. Reg. 60612 (October 13, 2006). The BART Alternative Rule allows an alternative program to source-by-source BART, if the program results in greater reasonable progress than would occur pursuant to individual BART.

States were required to submit their regional haze SIPs to EPA by December 17, 2007. The Regional Haze Rule establishes the year 2064 as the date by which a goal of visibility at natural background levels is desired in all Class I areas. The Rule divides the 2007-2064 time periods into numerous planning periods. States were required to submit their initial RH SIP by December 31, 2007, then a revised Regional Haze SIP to EPA by July 31, 2018, and every ten years thereafter. See 40 CFR Section 51.308(f).

Colorado submitted much of its regional haze SIP (including most of its BART determinations) to EPA in early 2008 for review. Following additional revisions, the Commission approved the remainder of Colorado's BART determinations in December 2008, and submitted Colorado's Regional Haze SIP to EPA's Region 8 for review in 2009.

Upon review, EPA Region 8 informed Colorado that its regional haze SIP submittal was not approvable and needed to be revised before EPA could reconsider it for inclusion in the State Implementation Plan. EPA has identified deficiencies with Colorado's Regional Haze Element of the SIP, including the basis for and enforceability of BART determinations and the lack of reasonable progress goals (RPGs) and RP source determinations. These alleged deficiencies must be addressed in order for EPA to approve the Regional Haze element of the SIP. This regulation is the second part of a bifurcated rulemaking process in which the Commission adopted the remaining outstanding Regional Haze SIP elements.

EPA made a finding on January 15, 2009 that 37 states, including Colorado, had failed to make all or part of the required Regional Haze SIP submissions. See 74 Fed. Reg. 2393 (January 15, 2009). This action started a clock by which states must have approved SIPs, or EPA must promulgate Federal Implementation Plans (FIPs) within two years (*i.e.*, by January 15, 2011). EPA initiated actions in Colorado to begin preparing a FIP, and this action by the Commission is taken to complete the adoption of a regional haze element of the SIP, address the deficiencies that Region 8 EPA has identified, and to prevent such a federal action in Colorado, with its attendant consequences (*e.g.*, federal determinations of BART, federal reasonable progress determinations, federal permits, and state loss of CAA grant monies so EPA can prepare a FIP).

During the 2010 legislative session, the Colorado legislature passed House Bill 10-1365, the "Clean Air - Clean Jobs Act" (CACJA). The CACJA sets forth requirements applicable to investor owned utilities in Colorado (Public Service Company of Colorado (PSCo) and Black Hills Energy) and certain of their electric generating units. The CACJA requires the investor owned utilities to submit emission reduction plans to the Colorado Public Utilities Commission (PUC), and provides that the Commission shall consider the air quality provisions of the emission reduction plans for incorporation into the regional haze element of Colorado's SIP. See Section 40-3.2-208, C.R.S. PSCo and Black Hills submitted their emission reduction plans to the PUC on August 13, 2010, and the PUC approved the plans on December 15, 2010.

The Commission adopted into Regulation Number 3 BART determinations for PSCo's Hayden and Comanche plants, two units at CENC's Golden plant, CEMEX's Lyons Portland cement plant, and Colorado Springs Utilities' Drake power plant. The Commission also adopted an Alternative to BART program for two units at Tri-State Generation and Transmission Association's Craig power plant. The Commission determined that, for nitrogen oxide (NOx) emissions, the appropriate BART control for Craig Units 1 and 2 would be emission rates associated with the assumed installation and operation of selective non-catalytic reduction (SNCR). As an alternative to BART, it was proposed and the Commission adopted, a more stringent NOx emissions control plan that consists of emission limits associated with the assumed operation of SNCR for Unit 1 and the assumed operation of SCR for Unit 2. The state has determined that the alternative program achieves greater reasonable progress than would be achieved through the installation and operation of source-by-source BART, and thus meets the requirements of the regional haze rule.

The Commission also adopted into Regulation Number 3 a BART Alternative for a number of PSCo plants and incorporated it into the Regional Haze SIP. The BART Alternative is based on reductions achieved as a result of a combination of shutdowns and retrofit emissions controls at certain PSCo facilities planned as part of HB 10-1365. The BART Alternative includes ten units at four PSCo facilities. The facilities included in the BART Alternative include Arapahoe Units 3 and 4, Cherokee Units 1-4, Valmont and Pawnee. The BART Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled by 2017 and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, fuel switching to natural gas as a peaking unit. For the BART sources, Cherokee 4, Pawnee and Valmont, Valmont will be retired by 2018, Pawnee will be fully controlled by mid-2015, and Cherokee will operate on natural gas by 2018. The state has determined that the BART Alternative achieves greater reasonable progress than would be achieved through the installation and operation of source-by-source BART and RP determinations at the covered sources, and thus meets the requirements of the Regional Haze rule. PSCo has designed and proposed the BART Alternative to meet the state CACJA. The Commission determined that to the extent there is any inconsistency between the CACJA and older, more generic legal requirements, the more recent and specific CACJA controls. The state has used simplifying assumptions to compare the emission reductions and visibility impacts associated with the PSCo BART Alternative, and believes that the BART Alternative is clearly superior to, and will result in greater reasonable progress than, source-by-source BART. For example, the state has determined and demonstrated that PSCo's BART Alternative emissions reductions are greater than, and would provide greater reasonable progress than, the presumptive or source-by-source BART limits. The Commission also adopted retirement dates of "no later than" July 1, 2012 and December 31, 2016 for Cherokee Units 1 and 3, respectively. In doing so, the Commission is no way rejecting any portion of PSCo's emission

reduction plan as approved by the PUC on December 15, 2010 (Decision No. C10-1328). Rather, the Commission's action is intended to provide flexibility and consistency in light of PSCo's pending application for rehearing, reargument or reconsideration (RRR) before the PUC, in which PSCo states that the revised dates are important for providing sequencing of activities that will ensure electrical system reliability in the Denver Metropolitan area. These dates are also wholly consistent with the PUC's decision because PSCo can comply with the dates established by both the PUC and the Commission, regardless of how the PUC rules on PSCo's RRR application. The Commission also notes that Hayden, another PSCo BART source, is not part of the BART Alternative program. The PUC approved controls for Hayden as part of PSCo's emission reduction plan under HB 10-1365, consistent with the state's BART determination for that source.

The Commission also established non-binding goals for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. See 40 C.F.R. Section 51.308(d)(1). The reasonable progress goals (RPGs) provide for improvement in visibility for the most-impaired (20% worst) days over the period of the SIP and ensure no degradation in visibility for the least-impaired (20% best) days over the same period. The Commission adopted into Regulation Number 3 emission limits for "reasonable progress" sources that have a significant impact on visibility impairment in Class I areas, in order to help the state make reasonable progress towards improving visibility in this first planning period. These sources include Black Hills Energy Clark Station (a HB10-1365 facility), the Holcim Cement Plant, Tri-State Generation and Transmission Association's Craig Station Unit 3 and Nucla Station, Platte River Power Authority's Rawhide Station, Colorado Springs Utilities' Nixon Power Plant, PSCo's Cameo plant, and CENC's Unit 3.

For all BART and BART Alternative determinations made by the Commission in the November 2010 – January 2011 proceedings, a source that has installed BART or implemented a state-approved BART Alternative is exempted from the imposition of further regional haze controls during this first regional haze planning period (i.e., through December 31, 2017). This exemption applies only to regional haze, and does not apply to controls or emission reductions that may be required or otherwise imposed pursuant to other air pollution programs (including, but not limited to, ozone standards).

The revisions to Regulation Number 3, Part F also apply Monitoring, Recordkeeping and Recording (MRR) Provisions to BART, BART Alternative and Reasonable Progress emission limits.

In addition to the regulatory changes described above, the Commission adopted changes to Colorado's Regional Haze SIP. Many of the changes are non-substantive edits while other changes address comments from Federal Land Managers, incorporate the justification for the BART and reasonable progress determinations, and provide the justification for the reasonable progress goals. The following presents an overview of the content of Colorado's Regional Haze SIP document:

Chapter 1 – Overview

Chapter 2 – Plan Development and Consultation

Chapter 3 – Monitoring Strategy

Chapter 4 – Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I area

Chapter 5 – Sources of Impairment in Colorado

Chapter 6 - Best Available Retrofit Technology

Chapter 7 – Visibility Modeling and Apportionment

Chapter 8 – Reasonable Progress

Chapter 9 – Long Term Strategy

Chapter 10 – Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

Chapter 11 – Resource and Reference Documents

Appendix A – Periodic Review of Colorado RAVI Long Term Strategy

Appendix B – SIP Revision for RAVI Long Term Strategy

Appendix C – Technical Support for the BART Determinations

Appendix D – Technical Support for the Reasonable Progress Determinations

The revised chapters are intended to fully replace previously adopted SIP chapters.

Additional Considerations

The Commission provides the following additional statement, consistent with Sections 25-7-110.5(5)(a) and 110.8, C.R.S.

() Colorado's proposed Regional Haze regulations and SIP revisions are consistent with EPA's federal requirements under the Regional Haze rule. There is no binding requirement on how a State may "consider" the federal statutory and regulatory factors in determining BART and RP and establishing RPGs. The manner and method of consideration is left to the state's discretion. States are free to determine the weight and significance to be assigned to each factor. See 70 Fed. Reg. 39104, 39170 (July 6, 2005). State discretion is a cornerstone of the regional haze rule. See id., at 39137 ("Congress evinced a special concern with insuring that States would be the decision makers."). States also have flexibility to consider any other factors that the state determines to be relevant. See U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 5-1 (June 2007). Federal law also allows states flexibility to adopt alternative programs that provide greater reasonable progress than BART. The Commission has adopted such alternatives for PSCo and Tri-State sources. The Commission finds that the revisions adopted in this hearing are wholly consistent with the discretion and expertise to be applied by state agencies under the federal act. Accordingly, the proposed revisions are no more stringent or different than federal law, and Sections 25-7-110.5 and 110.8 do not appear to apply.

Additionally, HB10-1365 provides, in part, that the Commission must vacate this rulemaking proceeding and must initiate a new proceeding for the consideration of alternative proposals for the appropriate controls for those units covered by the utility plans for inclusion in the regional haze element of the state implementation plan if, among other things, the Commission rejects any portion of the plans as approved by the PUC. Section 40-3.2-208(2)(b), C.R.S. If the Commission were to reject any portion of the utility plans, this proceeding would be vacated and a new proceeding initiated, making it impossible for Colorado to submit a timely and complete SIP revision to address Regional Haze, and resulting in a FIP. Under these circumstances, it is reasonable to conclude that the Commission rules regarding "1365" sources are being adopted to implement prescriptive state requirements, that the Commission has no significant policy-making options with respect to these sources, and that many provisions of Sections 25-7-110.5 and 110.8 do not apply. See Section 25-7-110.5(2), C.R.S.

Despite the foregoing, certain elements of this proceeding could be viewed (as certain parties have alleged) as exceeding the federal act or differing from the federal act. For example, the closure or repowering of PSCo facilities would not be required solely by EPA's Regional Haze Rule. Accordingly, the Commission is providing this additional statement, consistent with Sections 25-7-110.5(5)(a) and 110.8, C.R.S.

(II) EPA's regional haze requirements are performance based, and the regional haze rule sets forth factors that states must consider when assessing controls and emission limits for sources emitting visibility impairing pollutants. Section 169A of the federal Clean Air Act (1977) sets forth the following national visibility goal: "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution." 42 U.S.C. Section 7491. To help facilitate this goal, EPA finalized the regional haze rule in 1999. The Rule requires States to adopt SIPs to address visibility impairment in the Class I areas. Critical components of such SIPs (particularly the SIP for the first planning period) are BART and RP. EPA provides flexibility to states regarding how to apply the relevant factors to BART and RP analyses.

(III) Applicable federal requirements specifically address the issues regarding visibility impairment in Class I areas that are of concern to Colorado. Applicable federal requirements do not specifically address all of the issues that are of concern to Colorado. House Bill 10-1365 is intended to address Colorado's compliance with a number of federal Clean Air Act requirements in a comprehensive and more efficient fashion than in a step-by-step (or regulation by regulation) approach. The legislation specifically declares that it is intended to create "a coordinated plan of emissions reductions...to meet the requirements of the federal act...at a lower cost than a piecemeal approach." Section 40-3.2-202(1), C.R.S. While regional haze is an important consideration in the context of HB10-1365, it is not the only one. HB10-1365 aims to address other air pollution issues as well, including national standards for ozone. See, e.g., Sections 40-3.2-204(1), 204(2)(b)(II)(B) and 205(1)(c), C.R.S. Data regarding visibility impairing emissions and control technologies was considered in the federal process leading up to the promulgation of the Regional Haze Rule. See, e.g., EPA's "Technical Support Document for BART SO2 Limits for Electric Generating Units," April 1, 2005, and "Technical Support Document for BART NOx Limits for Electric Generating Units and Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet," April 15, 2005, Memoranda to Docket Number 2002-0076. These Memoranda reflect an analysis of all individual BART-eligible units in the country, including Colorado. See 70 Fed. Reg. at 39131-35. See also EPA's "Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations," U.S. EPA, June 2005. Additionally, the state determines that the regulatory requirements do not exceed the requirements of the federal act because the state is not imposing the BART alternative measures on an unwilling entity. Rather, the sources voluntarily proposed the packages as BART alternative measures and, in the case of PSCo, in order to comply with HB10-1365.

(IV) The adopted rule will provide certainty to sources, by providing necessary monitoring, recordkeeping and reporting mechanisms and clear timing requirements to ensure the achievability of the specified closure or performance based standards. With respect to the "1365" sources in particular, the requirements improve the utilities' ability to comply in a cost-effective manner while preventing or reducing the need for costly retrofits to meet more stringent requirements later.

(V) If the state does not take action by January 2011, EPA has indicated it will promulgate a FIP. The state and federal rules also have similar time frames for implementation. BART controls must be installed as soon as practicable but in no event later than five years after EPA approval of the regional haze SIP, and all BART, BART alternatives and RP controls must be implemented within this first planning period (i.e., before January 1, 2018).

(VI) The adopted rule will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rule establishes reasonable equity for sources subject to the rule by providing the same standards for similarly situated sources. BART and RP determinations are very source specific; different controls and emission limits are to be expected and reflect the State's source-specific consideration of federal statutory and legal factors, and of the state's implementation of HB10-1365.

(VIII) If the state rule were not adopted, EPA has indicated it will promulgate a FIP. This would likely result in more costly control requirements for sources which would be passed on to consumers.

(IX) The Regional Haze Rule requires associated State procedural, reporting and monitoring and recordkeeping requirements. The procedural, reporting, monitoring and recordkeeping requirements provided in Colorado's rule do not differ from, and often incorporate by reference, federal requirements.

(X) Demonstrated technology is available to control and monitor visibility impairing emissions.

(XI) The adopted rule will contribute to the prevention of pollution by reducing visibility impairing emissions.

(XII) A no action alternative would not address the required standard, and could result in EPA's promulgation of a FIP.

(XIII) All regulatory changes in this proceeding are based on reasonably available, validated, reviewed, and sound scientific methodologies. All information made available by interested parties has been reviewed and considered by the Commission.

(XIV) Evidence in the record supports the finding that the rule shall result in a demonstrable reduction of pollutants that contribute to regional haze.

(XV) Evidence in the record supports the finding that the rule shall bring about reductions in risks to human health or environment, and provide other benefits (e.g., protection of visibility) that justify the cost to government, the regulated community, and to the public to implement and comply with the rule.

(XVI) The Commission has chosen the alternative that is the most cost effective, provides the regulated community flexibility, and which achieves the necessary reductions in air pollution. The alternative will maximize the air quality benefits of regulation in the most cost effective manner. The Commission notes that no parties provided alternate proposals to the PSCo BART Alternative during this proceeding. The Commission also notes that in approving PSCo's emission reduction plan, the Colorado Public Utilities Commission thoroughly considered the economic impacts and concluded that that the approved plan comes at a lower cost to ratepayers than an all-controls option. Even if for some reason PSCo's BART Alternative were not determined to be the most cost effective option, the Commission finds that approval of the BART Alternative and incorporation of the alternative into the Regional Haze SIP is consistent with the legislature's intent in adopting the CACJA.

ATTACHMENT 7

Decision No. C10-1328

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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Submitted to Colorado PUC E-Filings System

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 NOx 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 NOx, SO_2, and mercury emissions between 2011 and 2018. Scenarios with relatively more coal burn tend to have higher emissions of NOx, SO_2, mercury, and CO_2.

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 NOx and SO_2 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 NOx 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 NOx, SO_2, mercury, and CO_2 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.

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 NOx reduction. CDPHE witness Mr. Tourangeau testified that the plan we approve here today will reduce NOx 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, NOx 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 NOx 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 NOx emissions, the plan we approve today will also reduce emissions of SO_2, 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

ATTACHMENT 8

Emissions Calculations for Xcel Plan 6.1.E

		2008 Emissions TPY[1]				
	2008 [2] mmBTU	PM	SO2	CO	NOx	Hg [3] (lb/yr)
Hayden						
Unit1	18,081,042	99.3	1,209.7	181.4	3,633.0	7.0
Unit 2	20,946,809	110.6	1,336.8	225.8	3,382.0	16.0
Cherokee						
Unit 1	8,794,175	36.3	2,532.9	86.6	1,970.3	2.0
Unit 2	7,900,437	33.4	1,900.4	79.4	3,148.4	3.0
Unit 3	11,677,769	62.6	664.5	122.5	1,930.9	5.0
Unit 4	26,439,306	87.1	1,667.4	264.1	4,225.5	6.0
Valmont	13,496,521	40.2	739.5	123.1	2,276.6	29.0
Pawnee	36,775,940	119.2	13,217.2	562.7	4,595.2	166.0
2008 emissions with Hayden		588.7	23,268.4	1,645.6	25,161.9	234.0
2008 emissions w/o Hayden		378.8	20,721.9	1,238.4	18,146.9	211.0
1x1 Replacement (2022)		52.6	4.1	122.6	111.0	0.0
2x1 replacement (2015)		105.1	8.2	245.3	221.9	0.0
2017 emissions - Plan 6.1.E with Hayden		521.3[4]	6,734.5[5]	1,479.3[6]	5,741.6[7]	45.6[8]
2017 emissions- Plan 6.1.E w/o Hayden		311.4[9]	4,197.7[10]	1,072.1[11]	4,285.2[12]	22.6
2017 Reduction with Hayden		67.4	16,533.9	166.3	19,420.3	188.4
2017 % Reduction with Hayden		11.45%	71.06%	10.11%	77.18%	80.51%
2017 Reduction w/o Hayden		67.4	16,524.2	166.3	13,861.7	188.4
2017 % Reduction w/o Hayden		17.79%	79.74%	13.43%	76.39%	89.29%
2022 emissions -Plan 6.1.E with Hayden		486.8[13]	4755.7[14]	1337.8[15]	3076.4[16]	39.6
2022 % Reduction with Hayden		17.31%	79.56%	18.70%	87.77%	83.08%
2022 emissions - Plan 6.1.E w/o Hayden		276.9	2218.9	930.6	1620.0	16.6
2022 % Reduction w/o Hayden		26.91%	89.29%	24.85%	91.07%	92.13%

[1] 2008 emissions data from Air Pollutant Emissions Notices submitted by PSCo.
[2] 2008 mmBTU data from the Clean Air Markets Division website.
[3] Mercury data from PSCo PUC submittal August 13, 2010, p. 20.
[4] Sum of 2008 PM emissions for Hayden 1 & 2, Cherokee 4 and PM emissions estimates for 2x1 replacement power.
[5] Calculated using 2008 mmBTU and SO2 limit at Hayden 1 of 0.13 lb/mmBTU, SO2 limit at Hayden 2 of 0.13 lb/mmBTU, SO2 limit at Cherokee 4 of 0.15 lb/mmBTU, SO2 limit at Pawnee of 0.12 lb/mmBTU and estimates of 2x1 replacement power.
[6] Sum of 2008 CO emissions for Hayden 1 & 2, Cherokee 4 and CO emissions estimates for 2x1 replacement power.
[7] Calculated using 2008 mmBTU and NOx limit at Hayden 1 of 0.08 lb/mmBTU, NOx limit at Hayden 2 of 0.07 lb/mmBTU, NOx limit at Cherokee 4 of 0.21 lb/mmBTU, NOx limit at Pawnee of 0.07 lb/mmBTU and estimates of 2x1 replacement power.
[8] Calculated using PSCo Mercury numbers and 90% control required by Colorado Regulation No. 6 for Pawnee.
[9] Sum of 2008 PM emissions for Cherokee 4 and PM emissions estimates for 2x1 replacement power.
[10] Calculated using 2008 mmBTU and SO2 limit at Cherokee 4 of 0.15 lb/mmBTU, SO2 limit at Pawnee of 0.12 lb/mmBTU and estimates of 2x1 replacement power.
[11] Sum of 2008 CO emissions for Cherokee 4 and CO emissions estimates for 2x1 replacement power.

Unit by Unit Calculation of NOx Xcel Benchmark 1 – 2008 Actual Heat Input; 2018 Estimated Emissions

	2008 mmBTU	NOx Benchmark 1
Hayden		
Unit1	18,081,042	723.2[1]
Unit 2	20,946,809	733.1[2]
Cherokee		
Unit 1	8,794,175	1,011.3[3]
Unit 2	7,900,437	908.6[4]
Unit 3	11,677,769	408.7[5]
Unit 4	26,439,306	925.4[6]
Valmont	13,496,521	472.4[7]
Pawnee	36,775,940	1,287.2[8]
Benchmark 1 total with Hayden		6,469.9
Benchmark 1 total w/o Hayden		5,013.5

[1] SCR at 0.08 lb/mmBTU installed in 2015, emissions reductions in 2016.
[2] SCR at 0.07 lb/mmBTU installed in 2016, emissions reductions in 2017.
[3] SNCR at 0.23 lb/mmBTU installed in 2014, emissions reductions in 2015.
[4] SNCR at 0.23 lb/mmBTU installed in 2014, emissions reductions in 2015.
[5] SCR at 0.07 lb/mmBTU installed in 2017, emissions reductions in 2018.
[6] SCR at 0.07 lb/mmBTU installed in 2016, emissions reductions in 2017.
[7] SCR at 0.07 lb/mmBTU installed in 2015, emissions reductions in 2016.
[8] SCR at 0.07 lb/mmBTU installed in 2014, emissions reductions in 2015.

BEFORE THE PUBLIC UTILITIES COMMISSION

STATE of COLORADO

DOCKET NO. 10M - 245E

DIRECT TESTIMONY OF PAUL R. TOURANGEAU ON BEHALF OF THE COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

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

INTRODUCTION

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Paul Tourangeau. My business address is 4300 Cherry Creek Drive South, Denver, Colorado, 80246.

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

A: I am employed by the Colorado Department of Public Health and Environment ("the Department"). I am the Director of the Air Pollution Control Division.

Q: HAVE YOU INCLUDED A DESCRIPTION OF YOUR QUALIFICATIONS, DUTIES, AND RESPONSIBILITIES?

A: Yes. A description of my qualifications, duties and responsibilities is included as Exhibit PT 1.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to provide the Department's assessment of Xcel Energy's ("Xcel's") emissions reduction plan reflected as Scenario 6.1.E ("Plan" or "Xcel Plan") developed pursuant to The Clean Air – Clean Jobs Act ("Act"), and to make certain reports and comments to the Public Utilities Commission regarding the Xcel Plan,

Submitted to Colorado PUC E-Filings System

as it is conditionally provided for in Xcel's Plan, the NOx emissions from the facilities subject to the Plan are expected to go from 18,147 tpy in 2008 to 4,285 tpy by the end of 2017, a 13,862 tpy reduction, which reflects an overall 76% reduction in NOx emissions from 2008 levels, so it achieves greater than 70% reduction in NOx by the end of 2017. Adding the retirement of Cherokee Unit 4 by 2022, the NOx emissions from the facilities subject to the Plan (excluding the Hayden facility) are expected to go from 18,147 tpy in 2008 to 1,620 tpy by 2022, a 16,527 tpy reduction, which reflects an overall 91% reduction in NOx emissions from 2008 levels, so it would achieve greater than 90% reduction in NOx by the end of 2022. The foregoing NOx emissions reduction figures reflect, include and account for NOx emissions from the 2015 combined cycle natural gas replacement power at the Cherokee facility (222 tpy NOx starting in 2015), and from the 2022 combined cycle natural gas replacement power at the Cherokee facility (111 tpy NOx starting in 2022).

Q: ARE THERE OTHER EMISSIONS REDUCTIONS FROM THE XCEL PLAN?

A: The Department estimates that, by the end of 2017, emissions from the Front Range facilities in the Plan, including emissions from the replacement power reflected in the Plan, will be reduced by 16,524 tpy SO_2, 166 tpy carbon monoxide, approximately 188 lbs/year mercury, and 67 tpy of direct total particulate matter based on the Division's analysis (Exhibit PT 3), and 8,000,000 tpy carbon dioxide from Xcel's analysis.[16] By 2022 with the closure of Cherokee Unit 4 and its replacement power reflected in the Plan, the foregoing emissions reductions increased by 1,978 tpy SO_2, 142 tpy carbon monoxide, 6 lbs/mercury, 34 tpy of direct total particulate matter by the Department's

[16] CPUC Docket No. 10M-245E, PSCo Clean Air-Clean Jobs Emissions Reduction Plan, August 25, 2010, p. 101.

Exhibit # 200
Docket # 10M-245E
Witness
Date 11-19-10

Submitted to Colorado PUC E-Filings System
Submitted to Colorado PUC E-Filings System

BEFORE THE PUBLIC UTILITIES COMMISSION

STATE of COLORADO

DOCKET NO. 10M - 245E

TESTIMONY OF PAUL R. TOURANGEAU ON BEHALF OF THE COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT REGARDING PUBLIC SERVICE COMPANY OF COLORADO'S FUEL SWITCHING EMISSION REDUCTION SCENARIOS 6E FS AND 6.1E FS

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

INTRODUCTION

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Paul Tourangeau. My business address is 4300 Cherry Creek Drive South, Denver, Colorado, 80246.

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

A: I am employed by the Colorado Department of Public Health and Environment ("the Department"). I am the Director of the Air Pollution Control Division.

Q: HAVE YOU INCLUDED A DESCRIPTION OF YOUR QUALIFICATIONS, DUTIES, AND RESPONSIBILITIES?

A: I previously included a description of my qualifications, duties and responsibilities as Exhibit PT 1 to the Department's September 17, 2010 testimony.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to respond to the Public Utilities Commission's (PUC) request that the Department provide its assessment of Public Service Company of Colorado's (PSCo) "fuel switching" scenarios, denoted scenario 6E FS and 6.1E FS.

1 **Q: ARE THE FUEL SWITCHING SCENARIOS LIKELY TO ACHIEVE A**
2 **GREATER THAN 70% REDUCTION OF NOx MEASURED FROM 2008**
3 **LEVELS?**
4 A: Yes.
5 **Q: WHAT NOx EMISSION REDUCTIONS DOES THE DEPARTMENT EXPECT**
6 **FROM THE SCENARIOS?**
7 A: Cherokee 4's NOx emissions rate under scenarios 6E FS and 6.1E FS is expected to be
8 0.12 lb/mmBtu,[1] reduced from the unit's current rate of 0.32 lb/mmBtu (2008). At this
9 level, Cherokee Unit #4 NOx emissions would be reduced from 4,225 tpy (2008) to 1,586
10 tpy, a 62% reduction operating at assumed 2008 conditions.
11 By the Department's calculation and assuming both a 0.12 lb/mmBtu emission rate and
12 Cherokee Unit #4 running on natural gas (assuming 2008 heat input levels), scenarios 6E
13 FS and 6.1E FS result in total projected NOx emissions of 3,095 tpy at the end of 2017
14 from the units in these scenarios (exluding Hayden). Compared to 2008 emissions of
15 18,147 tpy NOx (excluding Hayden), this reflects an 83% NOx reduction for each of the
16 two scenarios. Including Hayden in the scenario, these NOx emissions go from 25,169
17 tpy to 4,551 tpy for a total NOx reduction of 82% under the two scenarios (using figures
18 from PT-3).
19 **Q: ARE THERE OTHER EMISSION REDUCTIONS FROM CHEROKEE UNIT #4**
20 **ASSOCIATED WITH THESE SCENARIOS?**
21 A: Yes, there would be an effective elimination of SO2 emissions from Cherokee Unit #4 if
22 the unit were run on natural gas (from 1,667 tpy (2008) down to essentially zero). Fuel

[1] *See*, October 29, 2010, communication from Karen T. Hyde, PSCo, to Paul Tourangeau, CDPHE, attached hereto as Exhibit PT -7.

H.B. 1365: Applicability and Nitrogen Oxide Reduction Analysis for Public Service Company								
Coal-fired Generating Units								AQCC Regulation 3, 5 CCR 1001-5 Part F (**Attachment 6**) Rule VI.A (Hayden 1 & 2): BART (Selective Catalytic Reduction) Rule VI.C (All other units): BART Alternative (Shutdown or Fuel Conversion)
Unit Name / Number		Mega -watts ⊛	NOx Emissions (in tpy)		PUC Decisions C10-1328 / C11-0121 (**Attachment 7**)			
			Old †	New	Retire & Replace	Convert to Natural Gas	Emission Controls	
Valmont	5	186	2277	222‡	12/31/17			Shutdown 12/31/2017
Cherokee	1	107	1970		12/31/12			Shutdown no later than 7/1/2012
	2	106	3148		12/31/11			Shutdown 12/31/2011
	3	152	1931		12/31/16			Shutdown no later than 12/31/2016
	4	352	4226	1586¤		12/31/17		Natural Gas Operation 12/31/2017
Arapahoe	3	**			12/31/13			Shutdown 12/31/2013
	4					12/31/13		Natural Gas Operation 12/31/2014
Pawnee		505	4595	1287†			12/31/14	0.07 lb NOx/MMBTU (30-day rolling average) by 12/31/2014
Hayden	1	139	3633	723†			12/31/15	0.08 lb NOx/MMBtu (30-day rolling average) by 5 years after EPA's approval of the regional haze SIP
	2	98	3382	733†			12/31/16	0.07 lb NOx/MMBtu (30-day rolling average) by 5 years after EPA's approval of the regional haze SIP
Totals		1,645	25162	4551	Percent NOx Reduction ¤ 81.91%			

**The PUC previously approved retirement of Arapahoe 3 & 4, so their megawatts do not count toward the 900 MW requirement of §40-3.2-204 (2) (a) and their NOx reductions do not count toward the 70 - 80% NOx reduction requirement of §40-3.2-205 (1) (a).

⊛ See **Attachment 7**, PUC Decision C10-1328 (Valmont 5, ¶117; Cherokee 1, 2, and 3, ¶105; Cherokee 4, ¶129; Pawnee, ¶120; and Hayden 1 and 2, ¶124)

† See **Attachment 8**, Exhibit PT-3.

‡ See **Attachment 8**, Direct Testimony of P. Tourangeau, Sept. 17, 2010, p. 13.

¤ See **Attachment 8**, Exhibit 200, p. 2.

ATTACHMENT 9