THE STATE OF WYOMING

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December 16, 2013

Janet McCabe
Acting Assistant Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Mail Code: 6101A
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PSC LETTER NUMBER 13-173

RE: Section 111(d) Guidelines

Dear Assistant Administrator McCabe:

Thank you once again for the opportunity to meet briefly with you and your staff November 19th in Orlando. As promised, I am writing to elaborate on the concerns I outlined at that time.

The Wyoming Public Service Commission (PSC or Commission) urges the Environmental Protection Agency (EPA) to authorize the State, when applying standards for greenhouse gas performance related to electric power generation, to prominently consider "the remaining useful life of the existing source to which such standard applies," and in doing so to allow existing power plants to remain in operation for those lives. Section 111(d) of the Clean Air Act details a number of conditions that states have the authority to consider in developing standards of performance. The discretion afforded to states in section 111(d) is fundamental to establishing a state plan that accommodates each state's specific needs. This paper will illustrate possible economic consequences to ratepayers of Wyoming's two largest utilities, solely stemming from considerations to the remaining useful life of an existing source. As discussed in greater detail below, premature retirements of Wyoming electric generation facilities would have dire economic consequences.

Section 111(d) grants states the responsibility of determining the remaining useful life of existing generation sources to which a greenhouse gas standard may apply. In Wyoming, this would be an economic determination of the type commonly made by the Wyoming PSC, but which can and has been made by the Wyoming Department of Environmental Quality. The Commission has both the staff and an established analytical framework suited to determining remaining useful lives.

Wyoming regulates utilities as monopolies, principally by authorizing rates. Useful lives are a key component of rate determinations. At the simplest level, state law allows a utility to recover [i] operating and maintenance expense, [ii] a return *on* invested capital, also known as return on rate base, [iii] *a return of invested capital, or depreciation, which is tied to the useful life of capital assets* [emphasis added], and [iv] taxes. The Commission usually sets rates in general rate cases. In separate proceedings, public utilities may pass on known commodity or commodity related cost increases or decreases, including purchases of power.

In addition to setting rates, the Commission screens major capital investments by requiring utilities to secure a certificate of public convenience and necessity before commencing construction.

To illustrate the importance for EPA to adhere to the discretion afforded to states, below is a consideration of the circumstances for the largest public utilities in Wyoming. These public utilities share the common feature of owning generation facilities. The largest utility is Rocky Mountain Power, a subsidiary of PacifiCorp. Its most recent rates were based upon an annual Wyoming load of 9,543,820,000 kWh. Black Hills Corporation has two subsidiaries with operations in Wyoming, Cheyenne Light Fuel & Power and Black Hills Power. Cheyenne Light's recent annual load was 1,075,944,000 kWh. The Wyoming operations of Black Hills Power had an analogous load of 171,044,902 kWh.

<u>Rocky Mountain Power and PacifiCorp</u>

PacifiCorp operates in a vertically integrated transmission, generation, and distribution system with public utility status in six states: Utah, Oregon, Idaho, Wyoming, Washington, and California. Its subsidiary Rocky Mountain Power is a public utility in three states: Utah, Idaho, and Wyoming. The states have agreed to an allocation system known as the multistate protocol, which allows Rocky Mountain Power and PacifiCorp's other subsidiary, Pacific Power, to consistently allocate costs when the companies appear in state ratemaking proceedings. The principal signatories to the agreement are Idaho, Utah, Oregon, and Wyoming (California represents only 1.67% of PacifiCorp revenues). The terms of the multistate protocol have been subject to negotiated adjustment every five years.

The multistate protocol is an economic agreement, not an environmental regulation agreement. It follows that economic decisions and emissions consequences may easily diverge. One example involves PacifiCorp's Carbon plant, which will be closed because it could not comply with MATS standards.

The Carbon plant was scheduled to retire in 2020, but will now retire in early April 2015. Net book value of the plant as of December 31, 2013 was $50.3 million. Net decommissioning cost is estimated to be $20.1 million. Under a settlement in a general rate case in 2012, the Company agreed to reduce rate shock to customers by amortizing its remaining investment and net decommissioning costs through the original retirement date of 2020. This type of amortization is a common technique to reduce rate shock, but has its limits. Ratepayers are still paying for an asset that provides no service; pancaking amortizations can frustrate the original purpose; the duration of the amortization, and whether it is included in rate base, may be contentious.

When the Carbon plant closes, the multistate protocol will make Wyoming ratepayers responsible for 15.7% of the costs of over $70 million. The amortization treatment of the Carbon plant occurs against the background of a broader concern for rate shock. Over the past ten years, Rocky Mountain Power's Wyoming ratepayers have absorbed relatively large rate increases for purposes which include transmission investments essential to meet the national vision for a cleaner energy mix. In annual rate cases from 2005 through the end of 2011, and in separate proceedings to pass on energy costs (the Energy Cost Adjustment Mechanism, or "ECAM", and its predecessor PCAM), the Commission approved $210 million of increases:

General Rate Case			ECAM		
Docket Number	**Approved Revenue Change (millions)**	**Effective Date**	**Docket No.**	**Approved Revenue Change (millions)**	**Effective Date**
230-ER-05	$15.0	03/01/06			
230-ER-05	$10.0	07/01/06			
			266-EP-07	$2.45	7/01/07
277-ER-07	$23.0	05/01/08	315-EP-08	$28.8	10/15/08
333-ER-08	$18.0	05/24/09	341-EP-09	$7.07	09/01/09
352-ER-09	$25.5	07/01/10	363-EP-10	$4.4	04/01/10
352-ER-09	$10.0	02/01/11	389-EP-11	$13.6	11/01/11
384-ER-10	$44.6	09/22/11			
405-ER-11	$32.0	10/22/12	410-EP-12	$8.1	07/01/12
405-ER-11	$18.0	10/01/13	410-EP-12	$8.1	05/15/13
			410-EP-12	$8.1	05/15/14
			432-EA-13	$5.888	05/15/13
			432-EA-13	$5.888	05/15/14
			432-EA-13	$5.888	05/15/16
Total	**$196.1**		**Total**	**$98.3**	

In 2011, the Commission saw the first signs of ratepayer revolt among the industrial consumers who make up 71% of the PacifiCorp system load in Wyoming. Only 11% of consumers are residential; 17% are commercial. One industrial customer decided to generate its own electricity, and thereby reduced the total Wyoming load by 5%. This left the remaining 95% of Wyoming ratepayers to shoulder 100% of the costs associated with Wyoming's load, spreading costs over fewer ratepayers.

Although the unregulated generation of the defecting industrial consumer is presumably fired by gas, it represents a net addition to greenhouse gas emissions. Once PacifiCorp completes construction of its new Lakeside gas plant in Utah, estimated at $637 million, its current Integrated Resource Plan states that new resource needs for the coming decade can be met without further construction of generation, through demand side management and power purchases. Further defections of industrial consumers would adversely affect remaining ratepayers, and would not serve to reduce greenhouse gas emissions. As important, future defections may reflect a decision to close out business in Wyoming, rather than to privately generate electricity.

In the 2011 general rate case and filings following the defection, the Commission approved a settlement authorizing another $90 million - in addition to the preceding $210 million - in general rate increases and energy cost increases. To reduce rate shock, general rate increases took effect in two steps, and some of the energy cost increases were amortized to begin in 2014, 2015 and 2016, partly on the premise that energy cost increases would abate after 2014. The Company also agreed not to file another rate case until 2014, with no new rate increases to become effective before January 1, 2015.

When the next rate case is filed, the Commission anticipates continued upward pressure on general rates. The next increase will be driven in part by the new Lakeside gas-fired generation and in part by the Carbon plant settlement. Further increases will follow from pollution control projects to meet Regional Haze requirements, and at the turn of the decade will include costs related to the Company's Gateway West transmission project. Gateway West is needed to relieve transmission constraints affecting energy flow from east to west and affects further development of wind resources in eastern Wyoming. Rocky Mountain Power added 1,100 MW of Wyoming wind generation to the PacifiCorp system between 2007 and 2010, but further additions are not practical without additional transmission.

By agreement to the parties in the last general rate case, pollution control projects which cost more than $25 million cannot proceed without a certificate of public convenience and necessity. The parties to that rate case were concerned that the Commission rarely rejected major capital projects as imprudent once the Company had completed construction and submitted the projects for inclusion in rate base.

New pollution control and transmission projects are approved on a least cost, least risk basis, largely determined by complex modeling of the PacifiCorp system. To date, the Commission has approved construction of Selective Catalytic Reduction (SCR) for two units at the coal-fired Jim Bridger plant, and the Company has withdrawn a request for pollution controls at its coal-fired Naughton Unit 3 plant, substituting a gas-fired retrofit. Wyoming's State Implementation Plan for regional haze contemplated installation of SCR at the two units which have been approved by the PSC, and for the remaining two units at Jim Bridger. The SCR work on all four Jim Bridger units will cost in excess of $800 million.

A more recent development is that EPA's re-proposed rule for Regional Haze Compliance contemplates SCR technology for six more units in Wyoming, three units which are under the jurisdiction of the Commission: Naughton 1 and 2, which will be fully depreciated in 2029, and Dave Johnston 3, which will be fully depreciated in 2027. It is uncertain whether such retrofits will satisfy a least cost, least risk standard. No matter how the Company chooses to proceed, there will be substantial rate impacts if EPA's re-proposed rule stands, either through heavy capital expense for SCR facilities, or through premature retirement from service.

Assuming for a moment that Naughton 1 and 2 and Dave Johnston 3 are not prematurely retired, we can construct a simple demonstration of the effect of early retirements on ratepayers. The lives of the Company's coal-fired plants, and a related annual accrual which reflects remaining depreciation and net plant closure costs, are taken from a depreciation case concluded December 2, 2013:

Generating Station Retirement Dates
Rocky Mtn. Power Utility Plants

Utility/Plant	Probable Retirement Date	Original Cost	RMP Share of Output, MW	Annual Accrual Amount
Cholla (AZ)	Dec-42	$536,902,995	395	$14,809,596
Colstrip (MT)	Dec-46	$221,458,870	148	$2,557,702
Craig (CO)	Dec-34	$184,282,524	165	$5,186,596
Dave Johnston (WY)	Dec-27	$1,006,449,649	762	$56,233,241
Hayden (CO)	Dec-30	$85,317,975	78	$2,954,367
Hunter (UT)	Dec-42	$1,232,004,008	1132	$26,725,200
Huntington (UT)	Dec-36	$821,744,475	895	$27,831,570
Jim Bridger (WY)	Dec-37	$1,109,554,682	1411	$30,844,220
Naughton (WY)	Dec-29	$771,131,219	700	$36,245,988
Wyodak (WY)	Dec-39	$446,286,807	268	$13,090,257
Totals:		$6,415,133,204	5,954	$216,478,737

Using these accrual amounts, we can demonstrate stranded investment at five year intervals beginning in 2020 if all of the remaining plants were closed. We can also calculate the capital cost of replacing the MW output of the existing plants by using a $1159/kW cost for combined cycle turbine gas from the Company's current Integrated Resource Plan. The table below picks up the entries from the preceding table, in the same order:

Stranded Utility Plant Investment if Plants Retired In:

	2020	2025	2030	2035
Cholla (AZ)	$325,811,112	$251,763,132	$177,715,152	$103,667,172
Colstrip (MT)	$66,500,252	$53,711,742	$40,923,232	$15,346,212
Craig (CO)	$72,612,344	$46,679,364	$20,746,384	$0
Dave Johnston (WY)	$393,632,687	$112,466,482	$0	$0
Hayden (CO)	$29,543,670	$14,771,835	$0	$0
Hunter (UT)	$587,954,400	$454,328,400	$320,702,400	$187,076,400
Huntington (UT)	$445,305,120	$306,147,270	$166,989,420	$27,831,570
Jim Bridger (WY)	$524,351,740	$370,130,640	$215,909,540	$30,844,220
Naughton (WY)	$326,213,892	$144,983,952	$0	$0
Wyodak (WY)	$248,714,883	$183,263,598	$52,361,028	$52,361,028
	$3,020,640,100	$1,938,246,415	$995,347,156	$417,126,602
	Estimated Cost of Replacement Power			
	$6,900,686,000	$6,900,686,000	$5,115,826,000	$4,924,591,000
	MW Replacement Power Needed			
	5,954	5,954	4,414	4,249

Under the current multistate cost allocation protocol, Wyoming ratepayers would be responsible for 15.7% of the stranded investment and replacement with gas generation. 15.7% of $3 billion is $471 million. 15.7% of $6.9 billion is about $1.1 billion.

This is more than enough to result in further rate shock disruption. One only need consider that rate increases of $210 million over six years prompted a meaningful rate shock response; that $90 million of further increases have already been approved and are being implemented; and that substantial further pressure on rates begins with a rate case that will be decided by January 1, 2015.

In practice, it would be impossible to decommission the coal fleet and construct $7 billion of gas plants in a single year. Even if it were possible, it could not be done without skyrocketing costs, because the careful planning that is characteristic of prudent utility construction would go by the boards. The scale contemplated here would also require exogenous investment, such as new gas pipeline infrastructure.

Perhaps more important, the grid is an engineered system. In Wyoming's part of the west, the stability of the grid has been engineered over time using, in part, the inertia available to the system from heavy coal-fired turbines. Careful engineering would likewise be required to replace that feature of the present grid. In other words, replacing coal-fired generation is not like putting a car up on a lift and changing out its tires; it is more like replacing a tower of blocks one block at a time without having it collapse.

The simple calculation here does not attempt to either inflate or discount costs. What it nonetheless shows is that the economic impact of near term closure of coal facilities tails off substantially with the passage of time. By 2035, the stranded investment associated with premature retirement is about 14% of the same figure for 2020, and intervening retirements will dampen the effect of mass closure. However, the plants remaining in 2035 include some of the largest. Replacement will continue to be expensive, which is why the economics always tend to favor deferring replacement until existing facilities are retired.

<u>Black Hills Corporation, Cheyenne Light Fuel & Power, and Black Hills Power</u>

Although Cheyenne Light and Black Hills Power share a common parent, they own independent interests in generation facilities operated by Black Hills Corporation. By 2016, when it has the right to exercise an option to purchase the ownership interest of another BHC subsidiary, we anticipate that Cheyenne Light will own portions of the Wygen 1 and Wygen 2 plants. Black Hills Power will have ownership interests in Wyodak, Neil Simpson II, and Wygen 3. All of this coal-fired generation, with the associated emissions, is located in Wyoming, although over 90% of Black Hills Power customers and load are in South Dakota. The Black Hills Power operation in Wyoming is regulated as a separate Wyoming utility, whose rates are set by dividing up corporate costs. The Wyoming share of capital costs, determined in a 2010 rate case, is 7.07% of all Black Hills Power capital costs.

Cheyenne Light filed a general rate case on December 2, 2013, and Black Hills Power will file a rate case later this month. These cases are largely driven by investment in a new gas-fired plant, the Cheyenne Prairie Generating Station, which is scheduled to become operational in October 2014. Both utilities will also be seeking recovery for the MATS-related premature closure of the Neil Simpson I plant in 2014. Neil Simpson I was originally scheduled for retirement in 2023. The companies will propose to amortize $4.8 million of remaining book value and $3 million of decommissioning costs over 5 years.

Cheyenne Light requests increases which range from 8.5% to 12% for four classes of customers. These increases will generate $12,778,383 of additional revenue.

Like Rocky Mountain Power, Black Hills Power's Wyoming load is 69% industrial. Cheyenne Light's load is 37% industrial and 38% commercial, but the load characteristics of its commercial class strongly resemble the perpetual usage loads of industrial users. For example, Cheyenne Light's commercial class includes a Lowe's distribution center, a Walmart distribution center, a Microsoft data processing center, and a computing facility for the National Center for Atmospheric Research.

Unlike Rocky Mountain Power, Cheyenne Light and Black Hills Power have not weathered an unrelenting series of rises in rates. Since January 1, 2006, Cheyenne Light has received increases of $24 million in three general rate cases and two energy cost adjustment cases. Since 1991, Black Hills Power has received only a general rate case increase, of $3.1 million, in 2010.

Until the 2014 gas-fired addition to the Black Hills fleet, new Black Hills fossil fuel generation had been coal-fired. Generally speaking, these coal-fired plants are much earlier in their useful lives than most of the PacifiCorp fleet. The plants, with annual accruals for depreciation and net retirement costs, are as follows:

Generating Station Retirement Dates

Black Hills/Cheyenne Light Utility Plants

Utility/Plant	Probable Retirement Date	BHP/CLFP Share of Original Cost	BHP/CLFP Share of Output, MW	Annual Accrual Amount
Wyodak	2039	$109,320,705	67	$3,311,295
Neil Simpson II	2045	$143,600,267	80	$3,521,292
Wygen 1	2048	$126,225,000	65	$3,257,175
Wygen 2	2053	$184,542,756	95	$4,762,036
Wygen 3	2060	$130,212,144	52	$3,055,326
Total		**$693,900,872**	**359**	**$17,907,124**

Based on these accruals, one can again do a simple calculation of stranded investment and replacement power. The actual cost of the 2014 combined cycle turbine gas plant, $1,474/kW, is the basis for replacing coal with gas (this number is higher than for PacifiCorp because the presumed size of the PacifiCorp plants is several times larger, yielding economies of scale). The result is as follows:

Stranded Utility Plant Investment if Plants Retired In:

Utility/Plant	2020	2025	2030	2035
Wyodak	$62,914,605	$46,358,130	$29,801,655	$13,245,180
Neil Simpson II	$88,032,300	$70,425,840	$52,819,380	$35,212,920
Wygen 1**	$91,200,891	$74,915,018	$58,629,144	$42,343,271
Wygen 2	$157,147,188	$133,337,008	$109,526,828	$85,716,648
Wygen 3	$122,213,040	$106,936,410	$91,659,780	$76,383,150
Total	**$521,510,044**	**$431,974,431**	**$342,438,817**	**$252,903,204**
Total - CLFP	$248,348,079	$208,252,026	$168,155,972	$128,059,919
Total -BHP	$273,161,965	$223,722,405	$174,282,845	$124,843,285
Total - BHP WY	$19,312,551	$15,817,174	$12,321,797	$8,826,420

Estimated Cost of Replacement Power

	2020	2025	2030	2035
Total	**$529,166,000**	**$529,166,000**	**$529,166,000**	**$529,166,000**
Total - CLFP	$235,876,850	$235,876,850	$235,876,850	$235,876,850
Total -BHP	$293,326,000	$293,326,000	$293,326,000	$293,326,000
Total - BHP WY	$20,738,148	$20,738,148	$20,738,148	$20,738,148

MW Replacement Power Needed

	2020	2025	2030	2035
Total	**359**	**359**	**359**	**359**
Total - CLFP	160	160	160	160
Total -BHP	199	199	199	199
Total - BHP WY	14	14	14	14

For both companies, stranded investment and the cost of replacement power independently and collectively dwarf total rate increases in recent years, even assuming that the full rate increases requested in December 2013 are granted. Further, because none of the coal plants are scheduled for retirement by 2035, the required replacement power does not erode with the passage of time.

Other Generation Facilities

There are other generation facilities in Wyoming which are not within Public Service Commission jurisdiction, such as the 1,710 MW Laramie River Station operated by Basin Electric Power Cooperative. Missouri Basin Power Project participants from six states own the Laramie River Station, which delivers power to both the Eastern Interconnection and Western Interconnection. As such, it is another instance in which Wyoming emissions generate power largely distributed outside the state.

The state anticipates that there will be several options to arrange for analysis of the useful lives of facilities not subject to Public Service Commission jurisdiction, including interagency agreements and, if necessary, legislation.

Mass Emissions Option

Wyoming acknowledges Kentucky's proposal confirming the breadth of the flexibility principle. However, Kentucky's path is not likely to offer a viable solution for Wyoming.

Wyoming is an exporter of electricity – lots of electricity. Data from Energy Information Agency Forms 826, 906, 920, and 923 show:

2011 Wyoming Generation	MWh	%
Coal	40,961,449	85.98%
Hydroelectric Conventional	1,223,730	2.57%
Natural Gas	458,930	0.96%
Other	382,494	0.80%
Wind	4,611,868	9.68%
Total	**47,638,471**	100.00%

2011 Wyoming Retail Sales	MWh	%
Residential	2,802,726	16.09%
Commercial	4,353,082	24.99%
Industrial	10,261,954	58.92%
Total	17,417,762	100.00%
Available for Export	30,220,709	63.44%

Although Rocky Mountain Power and Cheyenne Light have active residential and commercial energy efficiency/demand side management programs, there is no residential and commercial program model that will make much of a dent in statewide emissions if they are calculated on a mass basis.

For the immediate future, the flexibility necessary for Wyoming to survive carbon regulation of existing power plants turns on the ability to use those existing assets for their useful lives.

As a final note, Energy Information Agency data shows a 5.5% decline in coal-fired generation emissions since 2005. In 2005, Wyoming generated 43,345,676 MWh from coal, as compared to the 40,961,449 MWh noted above.

Nothing in this document should be construed to support EPA's prospective regulation, as there is no indication of what it might entail. This paper does not constitute the comprehensive position of the State of Wyoming on this prospective regulation, nor does it touch on the legality of EPA regulating carbon emissions from stationary sources. The statements made in this paper are illustrative of possible effects on electricity rates and are meant to inform the EPA of the economic consequences that could result from a poorly drafted regulation or poor consideration to the discretion afforded to states in the Clean Air Act. This paper simply articulates two distinct facts. One, states are afforded great discretion in developing a standard of performance and a state plan. And second, allowance for the remaining useful life of existing sources will be integral in the development of a standard of performance.

Sincerely,

Alan B Minier

ALAN B. MINIER, Chairman
Wyoming Public Service Commission

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