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April 3, 2024

Kaitlyn Peterson
Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

Ms. Peterson,

Attached, please find my answers to the questions you emailed on March 27, 2024 under the December 20, 2023 cover letter. I hope these are helpful. Please let me know if you require anything further.

And thanks to the committee for asking me to participate in the hearings on these important issues. If I can be of future service, kindly let me know.

Sincerely,

Chris Parker
Director

The Honorable Rick W. Allen

1. Your office in Utah represents the interest of utility ratepayers. Can you walk us through how you evaluate costs when reviewing proposals at the Department of Public Utilities?

The Division's touchstone in reviewing costs and advocating for their inclusion or exclusion from rates is whether the costs are just and reasonable. Costs come before us for review in various ways and at various times. Generally, some costs are capital expenditures by the utility and some are expenses. A utility earns a return on capital expenditures but expenses are generally a simple pass through if they are prudent. For the purpose of discussing EPA's proposed rulemaking, capital expenditures are most relevant, although expenses passing through in the form of market transactions are also pertinent.

Capital expenditures generally enter rates after a general rate case, although some exceptions exist for some large investments. When a utility proposes capital additions for inclusion in rates, the justness and reasonableness of those costs is evaluated at the time the utility made the decision to invest. Nearly always, the investment has already been made, although some preapproval processes exist in Utah that utilities can employ to mitigate the risk of large investments. The utility will generally file its modeling and other documentation to support its chosen decision. Of course, the Division will review all material closely to ensure all assumptions are reasonable, the modeling is valid, and the like. But the modeling is always built on projections and projections of projections for all manner of costs. The only thing known for certain is that projections will be wrong. And once approved, ratepayers, not shareholders, will generally bear the risk of reality deviating significantly from projections.

Considering the information the utility knew or should have known, the Division is required to pursue the following statutory objectives:

- the safe, healthy, economic, efficient, and reliable operation of all public utilities and their services, instrumentalities, equipment, and facilities; and
- just, reasonable, and adequate rates, charges, classifications, rules, regulations, practices, and services of public utilities. Utah Code §54-4a-6.

The code further illuminates justness and reasonableness by providing the following criteria:

- maintain the financial integrity of public utilities by assuring a sufficient and fair rate of return;
- promote efficient management and operation of public utilities;
- protect the long-range interest of consumers in obtaining continued quality and adequate levels of service at the lowest cost consistent with the other provisions of [the code];

- provide for fair apportionment of the total cost of service among customer categories and individual customers and prevent undue discrimination in rate relationships;
- promote stability in rate levels for customers and revenue requirements for utilities from year to year; and
- protect against wasteful use of public utility services. Id.

As can be seen, weighing adequacy of service against costs, and maintaining utilities' financial integrity against accountability for poor management decisions is challenging. This is especially so when faced with federal environmental regulation and often inconsistent state policies.

In a state like Utah, where policymakers prefer to retain traditional generation assets for their operational lives,[1] especially with growing resource adequacy concerns, the decision to install expensive new control equipment might seem quite simple. But for a multi-state utility also facing bans of those same resources in other states, the decision is much less clear.

Once the utility has made its decision and presents costs for review in rates, the Division will apply the statutory guidance and arrive at a recommendation intended to balance all the factors. Given recent policy decisions from our Legislature, it is likely our recommendations will fall in favor of making investments to prolong the lives of traditional baseload generation.[2] The Public Service Commission will then consider all arguments and render its decision.

2. States have already approved cost-recovery for the existing generation this proposal goes after. If these resources retire, their costs will still be part of rates. If they do not retire, their capital costs will still be part of rates, and any compliance strategies or new generation will be added onto these rates. As someone who regulates with the public interest in mind, can you discuss if these proposed rules further the public interest from a cost perspective?

The proposed rules are likely to create high and unfair costs. Obviously, collecting remaining capital balances on plants closing early is unfair to future ratepayers who receive no benefit from the retired plants they will continue paying for. This is doubly so because the ratepayers in those periods will pay for retired plans and the new generation. In the regulatory arena, we often refer to this as intergenerational inequity because it shifts costs from one generation of ratepayers to another that didn't benefit from the resource. It is to be avoided.

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[1] See, e.g. 2024 Utah House Bill 191, Electrical Energy Amendments (requiring heightened burden for early closures of generation facilities).
[2] See, e.g. 2004 Utah Senate Bill 224, Energy Independence Amendments.

Adding expensive control technologies will also impose costs that would, in the absence of the rules, be imprudent. With plants in my purview expected to close between 2032 and 2042 already seeing declining, but still important, generation, large investments with limited or no economic benefits would generally be disfavored. The environmental effects of these technologies is relatively small. Adding hundreds of millions of dollars to rates for these investments will increase costs significantly with no offsetting generation or economic benefits. Without regulatory compulsion, this would not be in the public interest.

3. If new gas-powered resources are needed to diversify the resource mix because carbon storage or hydrogen are not readily available and/or because wind and solar cannot always operate, 100% of the costs of these new power plants will be borne by ratepayers. Can you justify ratepayers paying 100% of the costs for only 20% of the total resource's capability?

In general, the costs of renewable resources have been understated because most discussion leaves out the need for multiplying nameplate capacity and adding auxiliary resources to match the production lost by traditional generating resources. A fulsome view reveals the value of traditional generation sources is higher than some modeling and discussion suggests. While underlying information is confidential, recent analysis we have seen of all-in plant costs for a recent year weigh in favor of more traditional plant types. This is not to say that variable resources have little or no value.

There may be some benefits to the variable generation described. Ultimately, whether the generation can be justified for regulatory purposes will depend on complex modeling that depends on fuel price forecasts, electricity market price forecasts, and cost projections for various plant types. Obviously, if a facility provides more generation, its all-in costs to ratepayers will be lower per megawatt hour. Some lower-utilization resources can be justified as part of a broad and diverse portfolio, minimizing electricity costs. This, however, depends on wise planning and restraint concerning some resource types that bring with them other advantages, such as tax credits, satisfaction of other jurisdictions' policy goals, and the opportunity to deploy larger amounts of capital. Imbalance can creep in because of these concerns and provisions like the Public Utility Regulatory Policy Act, which can mandate purchase of resources a utility might otherwise not wish to add to its portfolio. NERC's addition of energy policy as a risk factor to analyze in resource adequacy reviews illustrates these facts.[3]

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[3] See 2023 ERO Reliability Risk Priorities Report, North American Electric Reliability Corporation, August 17, 2023, at 20.

The Honorable Russ Fulcher

1. The U.S. Energy Information Administration (EIA) reported that coal and natural gas, collectively, provided 60% of all electricity generated in the United States in 2022. Further, EIA said that as of March (prior to the EPA proposal) there were 38 gas-fired power plants totaling ~13,800 MW proposed to enter service in the coming years in the US. While not all were guaranteed to move forward, we would expect the prospects of many of them to be negatively affected by EPA's recently proposed power plant rule. What is the impact on ratepayers by cutting sources like coal-fired and coal- and LNG-fired power plants regardless of the approach – Carbon Capture and Storage (CCS) Hydrogen co-firing, or coal-fired plant retirements? Given this inflationary environment and the volatility of other energy sources, how would for example, public utilities be able to handle having to step up deployment of wind and solar projects to get approval from the EPA, forcing ratepayers to pay much more?

Cutting generation of coal and natural gas fired power plants will cost ratepayers more and subject them to decreasingly reliable service. A wise transition based on capability can improve the nations electrical system and its cost and reliability. A hasty one driven by hopes and projections is increasingly threatening our system and its cost and reliability.

Recent Utah experience illustrates this point. In late 2022, coal supply issues caused delivery shortages to PacifiCorp's Hunter and Huntington coal plants in Utah. Production difficulties and a mine fire limited supply, which reduced plant operations.[4] This required additional market purchases of electricity, as well as generation from more expensive sources. The market purchases to replace coal generation came at times of high demand in the west and prices for purchased power were significantly higher than the plants might have generated with their usual coal supplies. Coming in the winter, solar generation was not available for key hours of demand and wind was variable. As a result, reliable supplies that were needed to ensure the utility could meet demand had to be purchased from sellers with reliable supplies. The more coal and gas plants retire, the fewer these available suppliers and the higher the prices they command. Suppliers of such power can demand purchasers take large blocks of hours at relatively high prices to ensure physical supply.

As the question notes, as more traditional generation sources retire, utilities will be required to deploy far more other resources to meet demand. These resources, even if bringing comparable $/MWh prices per unit generated, will generate far fewer megawatts per facility. This means much higher capital costs will be found in base rates even when electricity markets might seem to suggest power is cheaper. The electricity markets' prices are driven by marginal costs of production, not all-in plant costs. Relying on more nameplate capacity to serve the

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[4] Rocky Mountain Power's 2022 Energy Cost Adjustment Mechanism Confidential Investigative Report, Idaho Public Utilities Commission Case No. PAC-E-23-09 (redacted available at: https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE2309/Company/202312222022%20ECAM%20Investigative%20Report%20-%20Redacted.pdf).

same demand will result in higher rates. Some of those increases will be seen in electricity markets as scarcity of dispatchable supplies influences prices. But much of the cost will also be found embedded in base rates for the capital costs of plants that aren't included in market bids and prices.

2. What will happen to baseload reliability during this transition from the current mix of energy sources to the mandated changed picture under the EPA's proposed rule? My state of Idaho has extensive growth, with power experts in the Northwest recommending the need for more power generation for the first time in years. If we're talking solar and wind, it is roughly 3,400 Megawatts per year. If it is natural gas, for example, it is only 800 Megawatts per year. In fact, the Northwest Power Council said that replacing 3,400 average Megawatts of existing hydropower or nuclear power generation would require nearly 5,500 average Megawatts of new wind and solar, as well as 2,000 Megawatts of natural gas. And yet, this rule knocks out a sizable portion of liquid natural gas, calling into question baseload reliability. Can you address your concerns over the poor choice of having to implement this rule and needing reliable and affordable energy?

As noted in my November testimony for the committee, both NERC and WECC are warning of reliability concerns as traditional baseload resources retire faster than their capacity or other capabilities are being replaced. Any acceleration of closures or diminished operational capacity due to EPA rules will exacerbate these risks. As the question intimates, it is unlikely enough resources can be built in time to replace any significant increase in plant retirements. And it is even less likely those resources, including their accompanying transmission investments, can be built to serve load as economically as retiring resources would be. Even simple disruptions in a utility's capital capacity, supply chain problems, construction delays can significantly alter timelines for new resources. Utilities, and subsequently utility regulators, will face the difficult question of whether to install costly controls on aging plants with limited periods to recoup the investment or to retire those plants and add multiples of additional nameplate capacity and related transmission to meet demand. Either way, costs will rise and reliability risks are likely to increase in critical periods.

3. Electric co-ops and other have raised concerns over EPA's timelines not being "realistic." Assuming the EPA meets its timelines, then state plans would not get approved until April 2027 at the earliest. That leaves less than three years for coal-fired plants to limit operations by 20% with the follow on retirements and other cuts to coal-fired and coal- and natural gas-fired plants, while installing the Carbon Capture and Storage (CCS) technology. Co-operatives have been involved in the development of CCS technologies and they are saying these technologies won't yet be ready. What is the effect on states that rely on the grid – partly powered by coal and natural gas – in

trying to comply with this rule? Given the EPA's track record in this regard and the continued litigation that will come from it, will states get their plans approved in adequate time by the EPA to implement trying to comply with this rule?

Past experience suggests EPA's timelines are unrealistic for a variety of reasons. These include lagging EPA action, litigation, and permitting challenges from EPA's sister agencies if approvals are needed for new investments in either existing plants or new resources. The experience of the Clean Power Plan undertaken by the Obama Administration, which the current rulemaking is designed to replace, is indicative. The original Clean Power Plan was initially proposed nearly ten years ago, with the final plan following roughly a year later. Litigation and subsequent administrations' changes have led us to the current moment. The goals originally envisioned in the 2015 plan were largely met without regulatory compulsion, only the threat of impending action. We can see now that many of the closures voluntarily undertaken in anticipation of future regulatory activity have introduced reliability risk into the nation's electric infrastructure.[5]

As the question notes, development of CCS technologies is proceeding. Time will tell the extent to which CCS can be economically deployed. But if adopted, additional time for permitting will be required. These timelines will make it virtually impossible to meet EPA requirements even if EPA acts expeditiously on state plans.

[5] 2022 Long-Term Reliability Assessment, North American Electric Reliability Corporation (December 2022); Western Assessment of Resource Adequacy, Western Electricity Coordinating Council (December 2022).