NOTICE OF CONFIDENTIALITY

A PORTION OF THIS TESTIMONY AND ATTACHMENTS HAVE BEEN FILED UNDER SEAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

IN THE MATTER OF ADVICE NO. 1797—ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8— ELECTRIC TARIFF TO IMPLEMENT RATE CHANGES EFFECTIVE ON THIRTY DAYS' NOTICE

Proceeding 19AL-0268E

ANSWER TESTIMONY OF PAUL CHERNICK

ON BEHALF OF SIERRA CLUB

PUBLIC VERSION

CONFIDENTIAL MATERIAL REDACTED ON PAGE 21
CONFIDENTIAL EXHIBITS PLC-25, PLC-26, PLC-27, PLC-28

SEPTEMBER 20, 2019

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Incorporated, 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight since 1990. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plants under construction, ratemaking for excess and/or uneconomical plants entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between

rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. My previous testimony has included many reviews of the economics of power plants, utility planning, marginal costs, and related issues.

Q: On whose behalf have you worked?

A: A large percentage of my testimony has been filed on behalf of consumer advocates (e.g., the Massachusetts, New Mexico, Washington, and Illinois Attorney Generals; other official public consumer advocates in Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, Pennsylvania, Illinois, Minnesota, Maryland, Ohio, Vermont, Indiana, South Carolina, Arizona, West Virginia, Utah, District of Columbia, and Nova Scotia; and such non-profit consumer advocates as AARP, East Texas Legal Services, Public Interest Research Groups, Alliance for Affordable Energy, citizens' groups, Ontario School Energy Group, Citizens Action Coalition, and Small Business Utility Advocates). I have also worked for regulatory bodies in Massachusetts, Connecticut, District of Columbia, and Puerto Rico, as well as the Vermont House of Representatives.

The remainder of my clients include investor-owned and municipal utilities, municipalities (New York City, Chicago, Cincinnati, several Massachusetts, New

Hampshire and New York towns in various proceedings), large customers, power-plant developers and owners, labor unions, energy advocates and environmental groups.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Sierra Club.

Q: What is the scope of your testimony?

A: I consider the following issues related to the rate request of Public Service of Colorado (PSCo or the Company):

- Examining whether Xcel was prudent in its engineering, construction, insurance and operation of the superheater at Comanche 3, and based on that, whether the costs of replacing the superheater were prudently incurred and should be included in the revenue requirement.
- Reviewing national experience indicating that coal plants are financially stressed nation-wide and are often not economic to continuing operating, especially when large capital additions would be required.
- Recommending an on-going economic screening process for future capital additions and other operating decisions at the remaining coal units, comparing costs of continued operation to derating and retirement.

Q: Please summarize your conclusions.

A: My review of the Comanche 3 superheater history strongly suggests that PSCo was imprudent, in some combination of the following: failing to pursue compensation from Alstom for the costs of Alstom's choice of an inappropriate alloy for the superheater

tubes; failing to adequately clean the superheater prior to operation and other operating errors; and failing to secure insurance against common-cause failure of multiple components.

My review of the literature on the history and economics of coal plants indicates that coal-fired generation is rapidly being phased out in the US, primarily for economic reasons. The viability of any coal plant is subject to question. PSCo should be regularly reviewing the economics of its coal plants, including in the context of any large capital investment, and sharing the results with stakeholders and the Commission. The Commission should be requiring regular reports on the cost-effectiveness of each unit. I suggest that the Commission require such reviews of economic viability in each rate case, prior to investments of more than 10% of the unit's gross book value or $100/kW, and at least once every two years, preferably at the midpoint between resource plan filings.

PSCo has failed to seriously confront its responsibility to monitor the economics of its coal plants and avoid uneconomic expenditures to extend the life of unprofitable plants. The Commission should therefore remind PSCo that even well-managed expenditures on an uneconomic plant may not be recoverable.

Q: Please summarize your recommendations.

A: I recommend that the Commission take the following actions:

- Review the prudence of PSCo's activities with respect to the Comanche 3 superheater problems.
- Disallow any costs of the Comanche 3 superheater tube failures that PSCo cannot demonstrate to be prudent.

- Require that PSCo justify its decisions to keep its coal plants online and continue to invest capital in such plants, starting with Hayden and Craig.
- Forcefully remind PSCo of its responsibility to prudently manage its power supply and minimize costs.
- Require that PSCo explain how it is embedding its strategic priorities in its capital and operational policies.

Q: What documents did you review in preparing this testimony?

A: I reviewed the direct testimony and exhibits of PSCo witnesses Kyle I. Williams and Brooke A. Trammell, various PSCo discovery responses, PSCo FERC Form 1 filings, tabulations of power plants maintained by the US Energy Information Administration (EIA), and several studies of coal-plant economics.

III. The Comanche 3 Superheater Replacement

A. Nature of the Problem

Q: What is the issue with the Comanche 3 superheater expenditure?

A: In this proceeding, PSCo is proposing to include in rate base $1 million spent to replace the Comanche 3 finishing superheater (FSH), as described by PSCo witness Kyle Williams:

> This project consisted of replacing the Comanche Unit 3 finishing superheater section with a different material. Tube failures in this section resulted in 6 to 7 percent of the current Unit 3 Unplanned Outage Rate. The build-up and exfoliation of oxides on the inside of the tubes caused tube pluggage which reduced or stopped circulation resulting in tube overheating and failure. The material exfoliation rate was expected to increase over time per the OEM. (Williams Direct at 29)

PSCo expanded on this explanation in discovery, as follows:

> The Comanche Unit 3 finishing superheater needed to be replaced due to experiencing multiple tube leaks associated with exfoliation. (SC1-5a)

> The tube failures occurred due to exfoliation. Exfoliation is when scale builds up on the inside of the boiler tubes. Unit 3 had an amount of buildup that would free itself from the boiler tube and ultimately block the flow of steam in the tubes. The steam is used to cool the boiler tubes and when it was blocked the tubes would have a short term overheat failure. (SC1-5(b))

The exfoliation caused repeated tube blockage, which resulted in overheating, which required outages to remove the blocked sections. PSCo finally decided to replace the entire FSH with stainless steel.

Q: How old was Comanche 3 when the FSH was replaced?

A: Comanche 3 entered service in July 2010, so it was only about five years old when PSCo replaced the FSH in 2015.

Q: Is replacement of a superheater for a plant just five years old unusual?

A: Yes, it is quite unusual. It is not easy to find data on the replacement of power-plant superheaters and related equipment, but I have found the following examples:

- Mr. Williams says that when PSCo replaced Pawnee's finishing superheater in 2014, "Pawnee's finishing superheater had been in service for 30 years." (Williams Direct at 28). Since Pawnee entered service in November 1981, the finishing superheater would have been at least 32 years old when PSCo replaced it.
- Asked about "the manufacturer's expected service life for the components of the finishing superheater section that were replaced," PSCo responded that "The design criterion reflects an expected 20-year life" (SC1-5(c)). Hence, the FSH lasted for only about 25% of its expected life.
- Babcock & Wilcox reports that it replaced the "horizontal primary superheaters" on San Juan 3 and 4 in 2007 and 2008, and various economizers and reheaters on San Juan 1 and 2 in 2008 and 2009. Units 1–4 entered service in 1976, 1973, 1979 and 1982, so they were roughly 32, 36, 25, and 29 years old at the time of the replacements.[1]

[1] The replacements were timed to coincide with outages for retrofitting of major environmental equipment (including a baghouse, low-NOx burners and activated-carbon injection), so the replacements may have been accelerated to avoid additional later outages. Available at: https://www.babcock.com/en/resources/case-profiles/san-juan-generating-station

- The EPA summarized the ages at which TVA had replaced large parts of superheaters (and associated boiler components) at multiple units, as shown in Table 1.[2] These varied from 21 to 37 years after initial operation. The EPA found that these projects were the first of their kind for each unit.

Table 1: TVA Coal Plant Major Superheater Projects

Unit	ISD	Replacement Date	Age at Replacement
Bull Run 1	1967	1988	21
Cumberland 1	1965	1996	31
Cumberland 2	1973	1994	21
John Sevier 3	1956	1986	30
Kingston 6	1955	1989	34
Kingston 8	1955	1989-90	34
Shawnee 1	1953	1989-90	36
Shawnee 4	1953	1990	37
Widows Creek	1954	1989-90	35

Overall, superheater replacement projects appear to normally occur between 20 and 40 years after a coal plant enters service, not five years.

[2] Decisions of the United States Environmental Protection Agency, Volume 9, United States. Environmental Protection Agency. Office of the Administrator, United States. Environmental Appeals Board at 403–404. https://books.google.com/books?id=i-oTAQAAMAAJ&pg=PA494&lpg=PA494&dq=superheater+replacement&source=bl&ots=k20luzEQLC&sig=ACfU3U1TVV6lnTHvCylYf5fdcinuQY2nww&hl=en&sa=X&ved=2ahUKEwjPp96-h4vkAhXyuFkKHR48DAs4FBDoATACegQIDRAB#v=onepage&q=superheater%20replacement&f=false

B. Potential Origin of the Problem

Q: What might have gone wrong, to result in the very early failure of the Comanche 3 superheater?

A: There are several possible ways in which this problem could have arisen, including at least the following:

- The design specified the wrong material or configuration.
- The manufacturer failed to use the proper material or fabricate the equipment to specification.
- The equipment was improperly installed.
- PSCo operated the unit incorrectly, such as by failing to maintain required water chemistry, fuel composition, ramping limitations or combustion conditions, or damaged the superheater during maintenance outages.

Q: Can you tell how the problem with the superheater actually arose?

A: Much of the material provided by PSCo suggests that the problem arose, at least in part, from the decision of the manufacturer, Alstom, to use particular metal alloys, T-91 and T-92, in the superheater tubes.[3] T-91 and T-92 are described as ferritic alloy steels with specific levels of chromium, molybdenum, vanadium, niobium and other elements, as summarized in Table 2.

[3] Since Alstom was responsible for engineering, procurement, and construction (EPC) of Comanche 3, the same party was responsible for design, fabrication, and construction.

Table 2: Components of T-91 and T-92 Steel Alloys[4]

	T-91 Alloy		T-92 Alloy	
Element	**Low**	**High**	**Low**	**High**
Chromium	8.00%	9.50%	8.50%	9.50%
Molybdenum	0.85%	1.05%	0.30%	0.60%
Manganese	0.30%	0.60%	0.30%	0.60%
Silicon	0.20%	0.50%	0.50%	
Vanadium	0.18%	0.25%	0.15%	0.25%
Carbon	0.08%	0.12%	0.07%	0.13%
Niobium	0.06%	0.10%	0.04%	0.09%
Phosphorus	≤0.020%		≤0.020%	
Sulfur	≤0.010%		≤0.010%	

The role of the selection of the alloys in the superheater failure is supported by the following information provided by PSCo:

- "The Comanche Unit 3 finishing superheater needed to be replaced due to experiencing multiple tube leaks associated with exfoliation." (PSCo Response to Discovery Request SC1-5(a))
- PSCo Response to Discovery Request SC 2-9(b) specifies that "it is Public Service's understanding that the use of T91 and T92 contributed to the referenced tube leaks and failures."
- "The boiler Original Equipment Manufacturer ("OEM"), Alstom, had used T91 alloys in other FSHs at other plants in a horizontal tube design, which validated

[4] From www.metalspiping.com/astm-a213-low-alloy-steel-tubes-for-boiler-superheater-heat-exchanger.html. See that web site for specifications for additional elements. Other manufacturers report similar composition.

the use of this material for the FSH. Comanche 3 and two other similar plants were developed in the same time-frame, using the same FSH design and materials, …" but in "approximately 2013, Public Service was informed that one of the other two plants was experiencing similar exfoliation issues in…FSH with the same design and materials." (PSCo Response to Discovery Request CPUC 6-3)

- Actually, both the other supercritical coal plants built by Alstom about the same time as Comanche 3 (Iatan 2 and J.K. Spruce) have suffered similar exfoliation problems in their superheaters (Attachment SC 1-7.A1 at 38).
- A 4/16/14 PSCo presentation included in Attachment SC1-7.A1 (at p. 22) says that "Grade T91/T92 alloys are exfoliating in some conditions at much earlier levels than anticipated" and "Exfoliated oxide can collect in tube bends and cause STOH failures."
- A 2104 PSCo power point included in Attachment SC1-7.A1 (at 37) refers to "Known issue with expedited oxide and exfoliation" in tubes made of T-91 and T-92 alloys.
- A 2007 Electric Power Research Institute (EPRI) study (part of Attachment SC1-7.A1) that discussed exfoliation of a number of alloys used in power-plant boilers describes in some detail the problems with T-91.

In addition, the Plainfield wood-burning power plant in Connecticut also needed to replace a superheater with T-91 tubes just a few years into operation.[5]

[5] *See HRSG Superheater Replacement*, *available at* https://hbbwinc.com/what-we-do/case-studies/hrsg-superheater-replacement/.

Q: When PSCo replaced the finishing superheater tubes in 2015, did it use a different material than the material used in the original tubes?

A: Yes. The replacement tubes were Super 304H stainless steel (SC 2-8). As PSCo explains in contrasting its experience with Pawnee's stainless FSH tubes with the T-91/92 tubes in the Comanche 3 FSH:

> The higher chromium stainless steel materials offer much greater resistance to steamside oxidation compared with the lower chromium T91/T92 materials for a given metal temperature. Recent EPRI research indicates likely ID oxide scale exfoliation issues within Grade T91 material are expected to occur within approximately 100,000 hours, with steam temperatures in excess of approximately 1040-1050 Fahrenheit. For stainless steel materials, once a stable internal oxide is formed, which occurs within approximately 30,000 hours of operation, exfoliation is not expected to occur even at much higher steam temperatures. The ASME Code allowed for the use of T91 material up to a design metal temperature of 1200 Fahrenheit; however, that is from the perspective of creep rupture properties, not a consideration of internal oxide scale exfoliation. (PSCo Response to Discovery Request SC 1-9(c)).

PSCo also explained that it expressly selected stainless steel as the replacement material to solve the exfoliation caused by the T91/92 tubes:

> After evaluation of the potential options, the Company determined that the best solution was to replace the entire finishing superheat section with a stainless steel material. Doing so would fully address the problem of exfoliation as methodology to address exfoliation in stainless steel tubes exist and are in use throughout the industry. (PSCo Response to Discovery Request CPUC 6-3).
>
> The use of internally shot peened SST [stainless steel] tube material is recommended in order to minimize future ID oxide scale exfoliation issues. (Attachment SC1-7.A3 at p. 3).

Q: Was there evidence of a problem with the use of T-91 in boiler tubes, prior to the in-service date of Comanche 3 in 2010?

A: Yes. The 2007 EPRI study, included in Attachment SC1-7.A1, discussed exfoliation of a number of alloys used in power-plant boilers.[6] Section 2.2 of that study describes problems with the T-91 alloy, citing earlier reports of the problems going back to 2001. For context, the Comanche 3 construction contract was awarded in April 2004, the contract was dated August 2005, with site preparation work commencing September 2005 and construction starting in January 2006.[7]

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[6] Electric Power Research Institute, Program on Technology Innovation: Oxide Growth and Exfoliation on Alloys Exposed to Steam, Report No. 1013666 (June 2007). See PSCo Attachment SC1-7.A1 at 45. It is not clear whether this is the "recent EPRI research" that PSCo mentions in PSCo Response to Discovery Request SC 1-9c.

[7] *See Comanche 3 Power Station Expansion, CO, USA, available at* https://www.power-technology.com/projects/comanche-3-expansion/

Q: Does PSCo offer any rationale for using a problematic material for the superheater tubes?

A: Yes. When asked "Given that this EPRI Report was published in June 2007,…why were T-91 and/or T-92 alloy tubes installed at Comanche Unit 3?", PSCo responded:

> The selection of T91 and T92 alloys was made by the boiler's Original Equipment Manufacturer ("OEM") Alstom, whose design preceded 2007 with a contract date of August 31, 2005. The use of T91 and T92 at up to tube metal design temperatures of 1200F was allowed prior to 2007, and is actually still allowed per ASME Section I (note this is based upon creep strength, not oxidation and exfoliation concerns). (PSCo Response to Discovery Request SC 2-9(c))

Q: What is the significance of this response?

A: PSCo appears to be implying that the specification of T-91/92 was reasonable at the time that Alstom selected it, because the 2007 EPRI study had not yet been published. But the EPRI study cites to published studies from as early as 2001 that identified corrosion and exfoliation problems with T-91 and T-92 alloys in superheater tubes.[8] Alstom appears to have ignored that evidence when it specified T-91/92 for the FSH and when it started fabrication of the finishing superheater. In 2011, as tubes started failing, neither Alstom nor PSCo appear to have quickly recognized the significance of the 2001–2004 studies or the 2007 report.

[8] PSCo Attachment SC1-7.A1 at 79–85; references at 98–99.

PSCo Response to Discovery Request SC 2-9(c) also suggests that the good creep strength of T-91/92 may have led Alstom (and possibly PSCo) to assume that the alloys were suitable for finishing superheaters in supercritical boilers.

Q: Did Alstom and PSCo immediately recognize exfoliation as the source of the superheater tube failures, once the failures started to occur?

A: No. PSCo claims that, in 2011, "there was not in-depth knowledge with respect to FSHs in a vertical tube configuration utilizing T91 alloys to assess that the metallurgy was at issue." (PSCo Response to Discovery Request CPUC 6-3). The 2007 EPRI study demonstrates that the exfoliation problems with T-91/92 had been known for a decade by 2011. PSCo does not define the level of "in-depth knowledge" that it would have required to reconsider using T-91 and T-92 alloys in the superheater tubes, either before construction, during construction, or once the finishing superheater operating problems arose. Nor does PSCo explain why it decided that the alleged lack of experience with T-91 in a specific design of finishing superheaters justified rejecting the prior adverse experience with T-91 in other boiler applications.

Q: So does the evidence in this proceeding unequivocally indicate that the failure of the Comanche 3 superheater was due solely to Alstom's error in specifying the tube alloy?

A: No. There is evidence that PSCo's operation of the plant may have initiated and/or exacerbated the problem. "Within twelve months of commercial operation, Public Service experienced tube leaks in the FSH. The Company's root cause analyses indicated that the tube leaks were due to operational issues attendant with operating new technology." (PSCo Response to Discovery Request CPUC 6-3). PSCo says that

"no internal exfoliation was evident" in radiography conducted in March 2014 (Attachment SC 1-7.A1 at 14, 31), suggesting that some other problem was causing the overheating.

Specifically, PSCo has identified three factors that may have contributed to the FSH failures: Inadequate boil-out, introduction of foreign objects into the steam system, and failure to insulate some vents.

Q: What is the evidence for PSCo's failure to properly boil out the steam system?

A: PSCo suggests that it failed to properly boil out the tubing (and other parts of the steam system) in two documents provided in discovery:

- PSCo's presentation in Attachment SC 1-7.A1 at 20 lists "incomplete boil-out" as among the root causes of the short-term overheating.
- PSCo concluded in 2014 that the short-term overheating was "Caused by improper boil[] out of tubes during start up." (Attachment SC 1-7.A1 at 35).

Q: What does it mean to "boil out" the superheater and related components?

A: Boil-out can refer to the process of cleaning out the system prior to operation, to strip out contaminants. "Preoperational contaminants include mill scale, weld slag, corrosion products, oil, grease, debris and dirt, temporary protective coatings, and other contaminants remaining after fabrication and erection of the unit."[9] Post-operational deposits "may include corrosion products, mineral scale, sludge, or process contaminants, in any combination. Deposits form from low levels of accumulation for long periods of operation, due to improperly controlled water treatment or process

[9] *See* https://www.suezwatertechnologies.com/handbook/chapter-15-chemical-cleaning-steam-generator-systems

contamination. Deposit characteristics are influenced by raw water characteristics, type of external treatment, feedwater treatment methods and control, and the nature and degree of external contaminants which have entered the feedwater during operation."[10]

Boil-out can also refer to drying out the tubes in the process of starting the boiler after an outage.

It is not clear whether PSCo's admitted failure to conduct proper boil-out referred to the pre-operational process, the operational period, or a combination of the two. There are references to PSCo improving start-up procedures (Attachment SC 1-7.A1 at 31, 32, 36), suggesting that some of the damage may have resulted from PSCo failing to properly dry out the steam system and ramping output up too quickly. Page 32 of Attachment SC 1-7.A1 lays out a ramping procedure that requires four 24-hour pauses during ramp-up, adding four days to the period necessary to bring the plant to full output and flexible dispatch.

Q: What is PSCo's current position regarding the prudence of its boil-out procedures?

A: PSCo now denies that improper boil-out resulted in the tube leaks:

[10] *Id.*

The boil out did not result in tube leaks; as Comanche unit 3 initially began suffering the exfoliation tube leaks, the site initially thought it was experiencing an improper boil out. To address this, the Company added a six hour boil-out period, and subsequently blew down the Electric Relief Valves to ensure the superheater was vacated of any water. It was after this that the Company discovered signs of exfoliation through use of radiograph. (PSCo Response to Discovery Request SC 2-6).

Q: What is the evidence regarding foreign objects in the FSH?

A: PSCo states that the short-term overheating was partially due to "foreign objects," other than the "exfoliated oxide" (Attachment SC 1-7.A1 at 20). Those foreign objects could have been introduced by Alstom in the construction process, and/or by PSCo during maintenance.

Q: What is the evidence regarding inadequate vent insulation?

A: PSCo alludes to potentially inadequate insulation of superheater vents in a few places in Attachment SC 1-7.A1:

- Page 30 states that "superheat vents P&ID found to be frozen during start-up during the 2/27/14 event," apparently referring to failure 12 listed on page 29.
- Page 32 describes operational changes required "until proper insulation installation can be completed," referring to the superheater vents that were found frozen and were not insulated.
- Page 34 refers to forced outages (on 2/27/14 and 3/4/14) from "short-term [FSH] overheating caused by plugged/frozen boiler vents not allowing proper boil out, i.e. condensation to clear the superheater circuits on start up." The second outage

was due to "a vent line from the Right Side FSH Outlet Header was not completely thawed during start-up after the 2-27-14 event…, which resulted in failures at the right side FSH assemblies." PSCo attributes a third outage on 3/9/14 as being due to "damage carried over from the previous events as a result of plugged/frozen boiler vents during start-up activities.

- Page 36: refers to dealing with "finishing SuperHeat Tube Leaks" by, among other things, "Insulating/Heat tracing vents."

In response to follow-up discovery, PSCo asserts that "When Comanche Unit 3 came online in 2010… [p]roper insulation of the roof vents had been installed." (PSCo Response to Discovery Request SC 2-4). PSCo has not reconciled this assertion with the statements that at least two of the tube failures were associated with frozen vents.[11]

Q: What can the Commission conclude regarding responsibility for the tube failures that led to the finishing superheater replacement?

A: The evidence I have reviewed suggests that the tube failures and associated replacement costs resulted from either or both of the following: (1) Alstom's error in specifying an inadequate alloy for the finishing superheater; and/or (2) PSCo failing to perform proper boil out of the system, ramping the unit too quickly, allowing "foreign objects" into the FSH, and/or failing to monitor and insulate the superheater vents.

[11] PSCo may mean that the vents were insulated to the extent required by the Alstom design when the unit entered service (which would be "proper," in one sense), even though the vents still froze under some circumstances, causing PSCo to determine that additional insulation would be "proper."

C. PSCo Management of the Liability

Q: Did PSCo seek compensation from Alstom for specifying the use of T-91 and T-92 alloys in the finishing superheater tubes?

A: No.

Q: Does PSCo explain why?

A: PSCo provides what purports to be an explanation of its failure to seek compensation from Alstom, suggesting that Alstom could not have known that the T-91 alloy would cause problems, because:

> "T91 alloys are used in coal boilers that operate at lower temperatures and pressures and are specified to withstand the pressures and temperatures at which Comanche 3 operates. The boiler Original Equipment Manufacturer ("OEM"), Alstom, had used T91 alloys in other FSHs at other plants in a horizontal tube design, which validated the use of this material for the FSH. Comanche 3 and two other similar plants were developed in the same time-frame, using the same FSH design and materials, which validated the use of T-91 alloy for Comanche 3." (PSCo Response to Discovery Request CPUC 6-3).

As explained above, the problems with T-91 and T-92 alloys were known before the construction of Comanche 3. For whatever reason, PSCo decided not to pursue damages from Alstom. It is unclear if this is in part because PSCo recognized that it had contributed to the damage, as I describe above.

PSCo also states in Response to Discovery Request Sierra Club 5-7 that the warranty expired May 25, 2012.[12] It is not clear whether PSCo belatedly realized, after the warranty expired, that PSCo could have pursued a warranty claim against Alstom. Indeed, PSCo does not specify when it first became aware that the use of T-91 and T-92 tubes was leading to exfoliation, which in turn contributed to the tube failures.

Finally, the PSCo Response to Discovery Request CPUC 6-3 suggests that negotiating with Alstom, rather than demanding compensation, reduced the cost of the replacement equipment:

> During these discussions Alstom provided proposals and the Company countered to provide material and construction services to replacing the tubing.…As noted in the referenced Attachments, the material supply offers were significantly reduced during the negotiation process as would likely have occurred had a warranty claim been made.

The reduction to which PSCo refers appears to be from an estimate of [redacted] (Confidential Attachment CPUC 6-3.A.3) to [redacted] (Confidential Attachment CPUC 6-3.A.5) to [redacted] (Confidential Attachment CPUC 6-3.A.6). At most, these documents suggest that PSCo might have saved [redacted] by negotiating with Alstom, but PSCo does not establish that this

[redacted] (Confidential Attachment CPUC 6-1.A1). The finishing superheater tube warranty would appear to have been extended into 2013 by the four FSH tube failures in 2010 and 2011 (Attachment SC1-7.A1).

was a better result than would be expected in the negotiation phase of any such contract. Nor does PSCo demonstrate that this reduction in the cost of replacing the superheater tubes exceeded the cost savings that PSCo could have obtained through making a warranty claim during the warranty period or through other action to recover the replacement costs from Alstom.

Q: Did PSCo seek to recover any of the costs from its insurance policy?

A: No. PSCo stated in a discovery response that:

> Public Service did attempt to determine whether any of its insurance policies would cover the cost of the superheater replacement. Each tube failure is considered a separate event subject to the deductible at the time, either $1.5M or $2M. Since the cost of each tube failure did not exceed the deductible, the Company did not file any claims. Please see the Company's response to Discovery Request SC1-7 for supporting documentation and communications. (PSCo Response to Discovery Request SC1-6(c)).

I do not see any discussion of insurance coverage in the Attachments to PSCo's response to Discovery Request SC1-7.

Q: Does PSCo's explanation make sense?

A: That explanation is disturbing, at best. PSCo has not provided the details of its insurance policies, or demonstrated that they really treat the failure of each tube to be a

separate event, even though they all resulted from a common cause.[13] There are several parts of a power plant that consist of multiple components that may fail at different times, even if they share an initiating event and require a large cost of remediation. Examples of those components include the main boiler tubes, the various superheater sections, reheat sections, air heaters and turbine blades. Insurance that does not cover incremental, premature failure of multiple, related components would not protect PSCo and its ratepayers in many situations. PSCo should explain its decision to purchase such limited insurance or explain why more comprehensive coverage for common-cause damage was unavailable or uneconomic.

Form PSCo's explanation, it appears that its coverage was comparable to a homeowner's policy that would apply the deductible to every window broken in a hailstorm, because a different hailstone hit each window, making each broken window a separate event under an insurance policy.

If PSCo believed that its insurer would recognize that PSCo was partly at fault for the tube failures, its incentives to pursue recovery would be limited. It is unclear from PSCo's testimony and discovery responses whether PSCo declined to make an insurance claim out of concerns that it would be found to have contributed to the tube failures.

[13] The common cause was most likely the choice of the wrong material for the finishing superheater tubes, but may have been PSCo's error in boilout, freeze prevention or other operation.

D. Costs of the Superheater Problems

Q: How much did the failure of the FSH tubes cost?

A: The problem, whether caused by Alstom, PSCo, or both, imposed three categories of costs:

- The capital cost for replacement of the superheater tubes, which was $11.7 million. (Williams Direct Testimony at 29).
- The cost of replacement power during each of the outages caused by tube failures. Unit 3 experienced 15 superheater tube failures between 2010 and 2014.[14] The Company estimates that each failure would require one week for repair, at a cost, at least in 2015, of $2.7 million per event.[15] (Attachment SC1-7.A3 at 2). That would total about $40.5 million in replacement power costs during repair of the 15 tube failures.
- The cost of replacement power during the extended outage to replace the superheater tubes with stainless steel tubing. Replacement of the tubes required an outage lasting 79 days (PSCo Responses to Discovery Requests LWG 8-4(a)

[14] Attachment SC1-7.A1 at 29 lists the dates of 14 outages, seven in 2010 and 2011, another seven in 2012–2014; page 35 cites 15 outages, including eight in 2012–2014.

[15] The $2.7 million is PSCo's estimate of the total or gross cost (not the incremental cost net of Comanche 3 variable costs) of replacement energy for a one-week outage in 2015 (PSCo Response to Discovery Request SC 5-5, 5-6, 5-12). The replacement costs may have been higher in earlier years. The Company has not estimated the incremental or net cost of the outages for the 15 tube repairs (PSCo Response to Discovery Request SC 5-12). Each failure also cost about $120,000 in O&M; depending on how rates were set in PSCo's 2014 Electric Rate Case (Proceeding No. 14AL-0660E), those costs may also have been passed on to customers.

and SC 5-5). At the replacement cost that PSCo estimated for 2015, that would be $30.5 million.[16]

Thus, the total cost to ratepayers consists of return, depreciation and taxes on $11.7 million, plus about $71 million in replacement power costs.

Q: How should the Commission deal with these costs?

A: The Commission should allow the costs of the finishing superheater replacement to be included in rates only if PSCo can demonstrate the following:

- the finishing superheater leaks and the need to replace the finishing superheater were not due to PSCo's imprudence,
- the leaks and the need to replace the finishing superheater were not due to Alstom's imprudence, or that PSCo prudently entered into a contract that precluded it from recovering the costs of Alstom's imprudence, and
- PSCo was prudent in relying on an insurance policy that would not cover multiple costs originating from a common cause.

If PSCo cannot show that the capital costs were prudently incurred, the Commission should not include in rate base the $11.7 million in capital costs for replacing the finishing superheater in 2015. In addition, if the Commission finds that the 2015 finishing superheater replacement costs were the result of imprudence, the Commission should, to the extent allowed by law and regulation, adjust PSCo's fuel-cost recovery to return to ratepayers the replacement energy costs incurred during the

[16] The Company has not estimated the replacement power cost (gross or net) of the extended outage to replace the superheater tubes (PSCo Response to Discovery Request SC 5-5).

15 outages caused by tube failures and the extended outage to replace the finishing superheater.

IV. The Economics of Coal-Fired Power Plants in the U.S.

Q: How are the economics of coal-fired plants in general relevant to the Commission's consideration of PSCo's revenue requirements in this proceeding?

A: The Commission and the parties do not have the resources to review in detail the efficiency of every aspect of PSCo's operations in a rate proceeding. Industry trends are useful indicators of areas deserving additional scrutiny, whether that is a decision to upgrade conventional customer meters when many companies are installing smart meters, failure to modernize communications with customers when many utilities are implementing text- and web-based communications system, or decisions to continue investing in generation technologies that are being widely replaced.

My specific interest here is in PSCo's continuing capital expenditures for existing coal plants and continuing expenditures on operating the plants.

Q: What coal resources does PSCo own, in part or in whole?

A: PSCo has partial or complete ownership of eight coal units, as listed in Table 3.

Table 3**: PSCo's Coal-Fired Units**

Coal Unit	In-Service Date	Summer Capacity	PSCo Share (%)	PSCo Share (MW)	Scheduled Retirement
Comanche 1	1973	325	100%	325	12/2022
Comanche 2	1975	335	100%	335	12/2025
Comanche 3	2010	750	66.67%	500	
Craig 1	1980	427	9.72%	42	12/2025
Craig 2	1979	410	9.72%	40	
Hayden 1	1965	179	75.5%	135	
Hayden 2	1976	262	37.4%	98	
Pawnee	1981	505	100%	505	

Since 2010, PSCo has retired or converted nine coal units to natural gas, totaling 1,076 MW at Arapahoe, Cherokee, Cameo and Valmont.

Q: What is the trend in installed coal plant capacity in the US?

A: At the end of 2010, the Energy Information Administration (EIA) listed 1,133 utility and Independent Power Producer (IPP) coal-fired steam power plants, excluding units listed as being out of service (and not expected to return) or on standby, with summer capacity of almost 312,300 MW. The EIA report for June 2019 lists 564 such units totaling 230,700 MW, with another 85 units and 23,034 MW scheduled for retirement by 2026.[17] Since that compilation, generation owners have announced at least two major retirements:

[17] *See* EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to From EIA-860)* (August 26, 2019) *Available at:* https://www.eia.gov/electricity/data/eia860m/

- Vistra has announced the 2019 retirement of six more units (Duck Creek, Havana, and two units each at Coffeen and Hennepin) totaling 2,000 MW by the end of 2019.[18]
- Santee Cooper has announced plans to retire two of its four 315-MW Winyah units in 2023 and the other two in 2027.[19]
- Tri-State Generation and Transmission Association moved up the retirement of 100 MW at its four Nucla units for 2022 to 2020, as part of a plan to lower rates by substituting lower-cost renewables.[20]

Table 4 summarizes the EIA data, with my additions from recent announcements.[21]

[18] *See Vistra Energy to Close Four Illinois Power Plants.(*August 21, 2019)*, available at* https://www.prnewswire.com/news-releases/vistra-energy-to-close-four-illinois-power-plants-300904904.html

[19] *See Santee Cooper to shutter half its coal over next decade* (August 29, 2019)*, available at* https://www.utilitydive.com/news/santee-cooper-to-shutter-half-its-coal-over-next-decade/561894/

[20] *See Nucla's Coal-Fired Power Will Close Early As Tri-State Aggressively Focuses on Renewables* (July 17, 2019), *available at* https://www.cpr.org/2019/07/17/rural-electricity-provider-announces-early-coal-plant-closure-focus-on-renewables/

[21] The 2018 data are from the 2018 Early Release, available at: www.eia.gov/electricity/data/eia860/.

Table 4: Coal Plants, 2010, 2018 and Projected

Year End	Summer MW	Units
2010	312,300	1,133
2018	238,089	595
2019	223,623	545
2020	218,336	517
2021	216,542	509
2022	212,829	497
2023	209,764	486
2024	207,832	480
2025	205,014	471

Of the currently operating units, only 14 units, totaling 8,500 MW, entered service after 2010.

In light of the significant trend of utilities retiring uneconomic coal units, any utility proposing to continue operating and investing in existing coal units should be prepared to demonstrate that customers receive benefits that exceed those costs.

Q: How much has PSCo spent on its coal plants since its previous rate case?

A: According to Attachment KIW-1, PSCo made $489 million in coal-plant capital additions in 2014–2018, dominated by the $290 million for the Pawnee SCR and scrubber. PSCo plans another $20 million in 2019. (Attachment KIW-2).

PSCo's FERC Form 1 report for 2018 shows $92 million in non-fuel O&M for its coal plants and $219 million for fuel (pages 402–403). Additional expenses—for payroll and property taxes, employee benefits, insurance, legal, regulatory, human relations, and the like—are required by these plants but recorded elsewhere in the FERC accounts.

Q: Has PSCo evaluated the economics of its coal units before making those capital expenditures and committing to continued operating costs?

A: No. In response to Sierra Club discovery request 3-1, PSCo stated that as part of the capital planning process, PSCo did not conduct an economic analysis of retiring and replacing any of its coal units prior to deciding whether to move forward with any of the capital projects. Similarly, in response to discovery request LWG 10-3, PSCo stated that it was not willing to conduct an analysis of whether it is more cost-effective to retire and replace any of its coal units prior to undertaking its 2019 capital expenditures at its coal units.

Q: What is the connection between ratesetting and the prudence of PSCo's operation of its system?

A: In most situations, a utility can recover costs from ratepayers if its decisions that resulted in the costs were prudent. Expenditures are prudent only if they are reasonably expected to provide benefits to ratepayers or are otherwise required (e.g., related to health and safety concerns). For example, the Iowa Utility Board has declared that

"should a rate-regulated utility continue to utilize an uneconomic facility, the Board may disapprove the costs incurred as imprudent or unreasonable during a rate case."[22]

Where there is reason to suspect that costs are imprudent, the utility has the burden to demonstrate prudence, if it can. That applies both to (1) activities that are clearly needed but may be unduly expensive due to utility mismanagement and (2) activities that are not clearly needed. For example, a certain number of distribution utility poles must be replaced every year, to replace damaged or rotten poles, and PSCo should be able to demonstrate that its purchasing and installation practices for those replacements were efficient. In addition, PSCo should be able to demonstrate that its pole-replacement decisions were prudent, and that it is not replacing perfectly adequate poles and adding the unnecessary cost to rates.

The same applies to power plants. PSCo may be imprudent in how it repairs a generation unit (e.g., overpaying, selecting the wrong repair technologies, etc.), but it can also be imprudent in repairing the unit at all, rather than retiring it.

Q: In practice, is every cost item usually subject to the same level of scrutiny in every rate case?

A: No. The regulators and the parties generally focus their attention on specific cost categories, based in part on the magnitude of the cost and whether there are indications that the cost may have been imprudent.

Q: How can the Commission deal with the issue of to whether PSCo has properly managed its coal fleet?

[22] Final Decision and Order, RPU-2018-0003, at 34 (December 4, 2018).

A: The Commission has a number of options. First, it may require that PSCo justify its decisions to continue investing in its coal plants before the capital additions are reflected in rate base or depreciation.[23] If PSCo's best efforts to justify continued investment in the coal plants (including units slated for retirement over the next several years) cause the Commission to decide that continued investment was imprudent, the Commission should disallow recovery of imprudent costs, or at least enough of such costs that the plants are not costing ratepayers more than the value of the plants.

Second, if the rate case schedule does not allow the Commission time to fully adjudicate the prudence issues, the Commission may disallow some portion of the costs of the least economic plants, as a best estimate of the result of analyses that PSCo has not conducted and presented.

Third, the Commission can put PSCo on notice that, considering the industry trends and the results of some analyses specific to PSCo plants, PSCo will need to demonstrate the prudence of continued operation of each of its coal resources to justify the capital additions and operating costs for the plants claimed in any future rate case.

Fourth, the Commission could open a proceeding to ensure that PSCo develops adequate cost-benefit analyses of coal-plant operation prior to the next rate filing.

Q: What data will you present regarding the economics of coal-fired power plants?

A: I will describe studies that examined the economics of specific PSCo coal plants; broader studies of the economics of coal plants; and the results of my analyses of the economics of coal plants over the last year or so.

[23] This approach can be extended to operating costs, as well.

A. Studies of the Economics of PSCo Coal Units

Q: Which studies have considered the economics of PSCo coal units?

A: The following studies have analyzed the economics of some or all of PSCo's coal units:

- Colorado Coal Plant Valuation Study: Economic assessment of coal-fired power plants in Colorado and potential replacement options, Edward Burgess, E., et al, Strategen Consulting, LLC, on behalf of Sierra Club, June 26, 2019.[24]
- PacifiCorp's analysis of the economics of its coal plants (2019 Integrated Resource Plan (IRP) Public Input Meeting, December 3-4, 2018), which include their shares of Hayden and Craig.[25]
- "PacifiCorp Coal Unit Valuation Study: A Unit-by-Unit Cost Analysis of PacifiCorp's Coal-Fired Generation Fleet," Energy Strategies, June 20, 2018.[26]
- "Half of U.S. Coal Fleet on Shaky Economic Footing: Coal Plant Operating Margins Nationwide," William Nelson and Sophia Liu, Bloomberg New Energy Finance (BNEF), March 26, 2018.

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[24] https://www.strategen.com/s/CO-Coal-Valuation-Study-Report-Final_public.pdf

[25] *See 2019 Integrated Resource Plan (IRP) Public Input Meeting December 3-4, 2018. Available at:* www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2018-12-03-04%20-%20General%20Public%20Meeting.pdf

[26] www.sierraclub.org/sites/www.sierraclub.org/files/PacifiCorp-Coal-Valuation-Study.pdf

1. Strategen's Analysis

Q: What did the Strategen study analyze?

A: The Strategen study considered the costs and alternatives for five coal units that PSCo owns in part or in whole (excluding Comanche 1 and 2 and Craig 1, because they have near-term retirement dates), as well as some coal units owned by other utilities. The costs included fuel, O&M, incremental capital expenditures, and dismantlement costs (which would favor later retirement). The alternatives included wind, solar, and market purchases.

Q: What did Strategen conclude?

A: Strategen found that ratepayers would be substantially better off replacing both Hayden units and Craig 2 with market purchases, solar, or wind. Strategen found that ratepayers would be slightly better off replacing Comanche 3 and Pawnee with solar or wind.

2. PacifiCorp 2019 IRP Analysis

Q: What information do the PacifiCorp IRP studies provide on PSCo coal plants?

A: PacifiCorp's analyses for its on-going IRP process included the four coal units (Craig and Hayden) that it co-owns with PSCo.

Q: What were the results for the units co-owned by PacifiCorp and PSCo?

A: PacifiCorp developed a number of analyses, using multiple models, approaches and assumptions. Table 5 shows PacifiCorp's results using its more sophisticated (PaR) model, for its base assumptions.[27]

Table 5: Estimated Savings from Retirement by Year ($/kW-year)

	2022	2025	2028
Craig 1	$38		
Craig 2	$60		
Hayden 1	$290	$193	$166
Hayden 2	$150		

PacifiCorp also analyzed a number of scenarios than included retirement of multiple units. The largest savings were from the cases in which Hayden 1 and Craig 2 were retired.[28] PacifiCorp is still developing its IRP (which is due to be filed October 18, 2019) and has not yet released its preferred portfolio; the results will be subject to regulatory review in multiple states.

3. Energy Strategies

Q: What information did Energy Strategies provide for PSCo units?

A: Energy Strategies computed the levelized cost of energy for each unit through 2026 for Craig 1 (the retirement date assumed by PacifiCorp) and 2046 for the other units co-owned with PacifiCorp. Energy Strategies found that Craig 1, Craig 2, Hayden 1 and

[27] 2019 Integrated Resource Plan (IRP) Public Input Meeting, December 3-4, 2018, p. 10.

[28] *Ibid*, pp. 58–59.

Hayden 2 were all substantially more expensive than market purchases at Four Corners or new wind, and that compared to new solar resources, the Craig units were slightly more expensive and the Hayden units much more expensive.

Table 6 reproduces part of Table 8.5 from the Energy Strategies Report.[29]

Table 6: Levelized Cost of Electricity, Energy Strategies Study ($/MWh)

Plant	Unit	Coal	Market Purchases	Utah Solar PV	Wyoming Wind
Craig	1	$39.71	$33.66	$38.55	$27.56
	2	$42.71	$33.66	$38.55	$27.56
Hayden	1	$47.07	$33.66	$38.55	$27.56
	2	$49.75	$33.66	$38.55	$27.56

All four Craig and Hayden units were more expensive than market purchases, wind, and even solar in this analysis.

4. The BNEF Study

Q: What did the BNEF study examine?

A: The Bloomberg study, attached as Exhibit PLC-2, covered the six-year period of 2012 through 2017, for 903 units totaling 280 MW of nameplate capacity, excluding combined heat and power units. The authors compared energy, capacity and byproduct revenues by unit to the fuel, variable O&M and emissions charges, to compute what they call the "short-run margin." Adding fixed O&M to the costs produces the "long-

[29] The Craig and Colstrip labels were reversed in the original; I have corrected that error.

run margin." The study reports environmental capital additions, but does not include any capacity additions in the profitability analysis.

Q: What did the BNEF study conclude?

A: The study's conclusions included the following:

> By our estimates, 48% of the coal fleet (135 of 280 GW) posted negative margins from 2012-17…
>
> We find ourselves awestruck by the resilience of U.S. coal. Plants persist even when they cost more to run than replace. As we hunt for coal closures, beware of the sometimes tenuous link between 'economics' and 'retirement decisions'. The link is especially weak in regulated regions, where high-cost coal runs regularly out of merit. …
>
> The majority of 'uneconomic' units (130GW of 135GW) are regulated. They are kept online by virtue of cost-plus pacts that partially insulate owners from shifting economics. … (p. 1)
>
> Coal plants were originally designed to run baseload – to sell large volumes of electricity with healthy short-run operating margins (i.e. dark spreads). This was necessary to cover relatively high fixed costs. Since the shale boom, collapsing dark spreads and dwindling capacity factors have cut deeply into coal's energy revenues – so much so that plants sometimes fail to cover fixed operating costs. Ongoing operating losses can drive plants to retire.

> Simply boosting output is not an option. Plants have reduced their capacity factors precisely because in many hours, fuel prices are higher than power prices. Running more would mean running at a loss. (p. 8)

Q: What does BNEF conclude about PSCo's coal plants?

A: Table 7 provides BNEF's results for each of the PSCo units, for each year and cumulative for the period. In this analysis, the revenues for Craig and Hayden substantially exceeded their fuel and O&M. The Craig units lost money in three of the six years and were slightly uneconomic overall in the BNEF analysis. The Hayden units lost money in four of the six years and were strongly uneconomic overall.

Table 7: BNEF Estimates of PSCo Unit Operating Profit ($/kW-year)

	2012	2013	2014	2015	2016	2017	Average
Comanche 1	$48	$169	$195	$32	$26	$44	$86
Comanche 2	$22	$107	$218	$24	-$1	$65	$73
Comanche 3	$73	$200	$217	$69	$78	$124	$127
Craig 1	$20	$58	$140	-$61	-$117	-$59	-$3
Craig 2	$2	$82	$168	-$76	-$124	-$62	-$2
Hayden 1	-$99	$21	$43	-$163	-$200	-$181	-$97
Hayden 2	-$77	$80	$92	-$112	-$112	-$95	-$37
Pawnee 1	$69	$172	$156	-$24	-$7	$77	$74

Since these are the annual profits without capital additions or overheads, these results understate the losses that PSCo's customers may have experienced from Craig and Hayden. Including capital additions and overheads, the losses on those units would be even larger, and the margins for Comanche and Pawnee would be smaller.

B. Other Studies of Coal Economics

Q: Have other recent studies reviewed the prospects for economic coal plant operation?

A: Yes. While there have been several such coal-plant cost-effectiveness studies, the ones conducted in 2018 and 2019 that are specific enough to be useful include:

- "The Cost of Preventing Baseload Retirements: A Preliminary Examination of the DOE Memorandum," Metin Celebi, et al, the Brattle Group, July 2018.[30]
- "Powering Down Coal: Navigating the Economic and Financial Risks in the Last Years of Coal Power," Matt Gray, et al, the Coal Tracker Initiative, November 2018.[31]

1. The Brattle Study

Q: What were the results of the Brattle study?

A: The Brattle Group study, attached as Exhibit PLC-3 used ABB's Velocity Suite data (the default data for PROMOD) to estimate the 2017 net margin for each domestic coal plant (as well as each nuclear plant).[32] Brattle does not identify the results for specific units, but does provide aggregate results, as summarized in Table 8.

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[30] https://elcon.org/the-cost-of-preventing-baseload-retirements/

[31] https://www.carbontracker.org/reports/coal-portal/

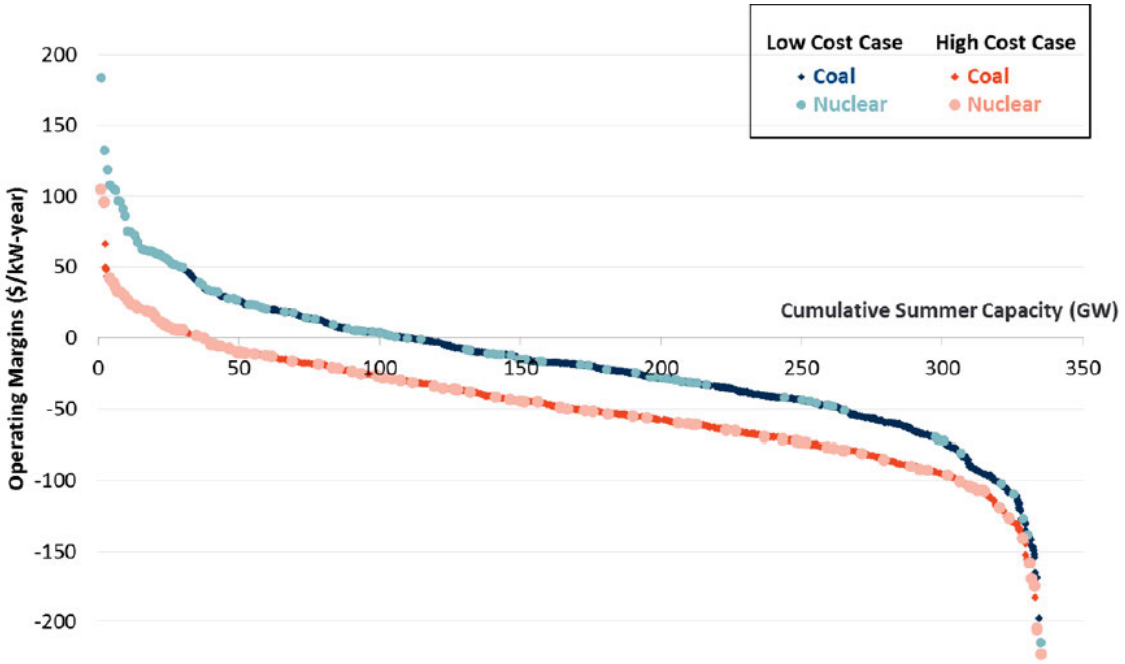
[32] Brattle reports that it excluded another 11.7 GW of coal units (averaging 37 MW per unit) that were listed as having no generation and in most cases no cost data.

Table 8: Brattle Results for Coal Plant Economics, 2017

	Capacity with Revenue Shortfall				
		Gigawatts		Percentage of Total	
	Total Capacity (GW)	Low-Cost Case	High-Cost Case	Low-Cost Case	High-Cost Case
RTO	160.1	120.1	154.2	75%	96%
Non-RTO	75.7	65.3	69.5	86%	92%
Total	235.8	185.4	223.7	79%	95%

Brattle also plotted the distribution of plant profitability, as shown in Figure 1.

Figure 1: Brattle Summary of Power Plant Cost-Effectiveness, 2017



The dark data points, representing the coal plants, are sometimes obscured by the large light data points that Brattle used for the nuclear units.

2. Carbon Tracker Institute

Q: What did the Carbon Tracker Institute study analyze?

A: The Carbon Tracker Institute compared the forward-going cost of each coal plant (in the US and globally) to the costs of local renewables. It found that 70% of US coal plants were more expensive than renewables in 2018, rising to nearly 100% in 2030. The report does not provide results by plant, or even by utility.

C. My Recent Analyses of Coal-Plant Economics

Q: For which coal plants have you recently reviewed the economics of operation?

A: Since June 2018, I have reviewed the cost-effectiveness of continuing operation of 29 coal units by six utilities: Westar in Kansas, MidAmerican in Iowa, Cleco in Louisiana, Interstate Power and Light (IPL, a unit of Alliant) in Iowa, and two subsidiaries of WEC Energy, Wisconsin Public Service (WPSC) and Wisconsin Electric Power (WEPCo).

Each of these analyses assumed that the sunk costs of the plant (e.g., the gross investment net of accumulated depreciation) would be recovered in the same manner, regardless of whether the plant operated or was retired. I compared the forward-going costs of the units to market revenues, the market costs of replacement energy and capacity, and/or renewables.

All of these proceedings are listed in my qualifications, Exhibit PLC-1.

Table 9 summarizes my conclusions regarding the plants that were not already scheduled for near-term retirement.

Table 9: Recent Analyses of Coal-Plant Economics

Utility	**Unit(s)**	**ISD**	**Economic?**
Westar	Lawrence 4		No
	Lawrence 5		No
	La Cygne 1–2		No
	Jeffrey 1–3		No
MidAmerican	Neal 3		No
	Neal 4		No
	Ottumwa		No
	Louisa		No
	Scott 3–4		Marginal
Cleco	Big Cajun 1		No
	Big Cajun 2		No
	Rodemacher		No
	Dolet Hills		No
	Madison		Marginal
IPL	Lansing		No
	Neal 3		No
	Neal 4		No
	Ottumwa		No
	Louisa		No
WPS	Columbia 1–2		No
	Weston 3		No
	Weston 4		No
WEPCo	Oak Creek 5–8		No
	Elm Road 1–2		Marginal

I also reviewed some units that had been recently retired or were scheduled to retire within a couple years. I agreed that all those units were uneconomic.

Of the 29 coal units that were not already retired or close to retirement, 26 were clearly uneconomic.[33]

[33] Note that four units are jointly owned by IPL and MidAmerican, and thus are listed twice in Table 9.

V. PSCo's Failure to Account for Deteriorating Coal-Plant Economics in Capital and Operational Planning

Q: How does PSCo reflect the deteriorating economics of coal plants in its operations?

A: If we take PSCo at its word, it ignores the economics of continued operation of its coal units during its capital planning decisions. When asked the following question:

> For the years 2014 through 2019, in developing capital budgets for the Comanche, Craig, Hayden, and Pawnee units, did PSCo conduct an analysis of retiring and replacing any of the units instead of implementing capital projects? For the purposes of this request, "analysis" means a cost-benefit analysis of retiring and replacing a unit rather than moving forward with a capital project and/or a study of the economics of retiring and replacing a unit relative to continued operation of the unit.

PSCo responded:

> No. The Company's capital project review and analysis does not drive the Company's electric resource planning process. The capital project review process uses the planned retirement dates as set forth in the Company's electric resource planning analysis. (Discovery Request SC3-1)

And when asked the following question about whether it was willing to even consider whether future investments were prudent:

> With respect to the response to SC1-17, (analysis of 2019 capital expenditures at PSCo coal plants), please indicate if PSCo is willing to conduct an analysis of the most cost-effective alternatives if these coal plants are to be retired by 2030 before undertaking the 2019 capital expenditures.

PSCo responded that it was not willing to even consider the prudence of continued operation:

> No. The Company has demonstrated the reasonableness of the requested 2019 capital additions in the Direct Testimony of Kyle Williams. More generally, and consistent with the objection set forth above, the Company's resource planning and actions necessary to meet its resource needs are addressed pursuant to the Commission's electric resource planning rules. (Discovery Request LWG10-3).

Q: Are these Company responses reasonable?

A: No. Before spending money on fixing, maintaining, repairing or improving a marginal asset, any responsible publicly traded corporation would consider whether it was worth doing so. Shareholders should be enraged if management were throwing good money after bad, or not even asking whether the expenditures would increase earnings. PSCo seems to be saying that management does not feel the same obligation towards ratepayers that its fiduciary responsibility would require for its shareholders.

Interestingly, PSCo claims it conducts cost-benefit analyses of alternatives during its capital planning process. (PSCo's Response to Discovery Request SC 3-3). Yet PSCo also admits that its cost-benefit analyses during the capital planning process

ignore the alternative of retiring the a generation unit, no matter how large the proposed capital investment, and no matter how doubtful the unit's economics may be. (PSCo Response to Discovery Request SC 3-1). PSCo's policy is economically inefficient and unreasonable.

The position expounded by PSCo would be similar to a household deciding every third January when it will replace its vehicles, yet between those transportation resource decisions, spending whatever is necessary to keep the existing cars running. It would make little economic sense to separate the household's personal transportation planning from their transportation budgeting in the manner that PSCo says it separates "capital project review and analysis" from its "electric resource planning process." If it becomes clear that a car is costing more than the cost of equivalent transportation service (e.g., the cost to purchase another car, an alternative vehicle, or take public transit), it would be economically rational to retire the car, regardless of where the household is in a hypothetical transportation planning cycle.

PSCo cannot claim to be prudently managing its generation supply when every public analysis shows the Craig and Hayden units to be uneconomic, yet PSCo does not bother to analyze whether it makes sense to keep making capital additions at Craig and Hayden.

Q: Why does it matter whether PSCo separates its decisions about capital and operational budgeting for its coal plants from its resource planning decisions?

A: Balkanizing decisionmaking can lead to severely suboptimal outcomes. For example, if PSCo simply keeps running Hayden because it has not examined the economics of replacement options, the units may run for several more years, continuing to burden

ratepayers, when a rational decisionmaker would shut the plant down rather than make continued capital additions.

Or suppose that some major piece of equipment at Comanche 2 suffers a failure in late 2019, similar to the superheater leaks at Comanche 3. Under its planning philosophy, PSCo would repair or replace the failed equipment, since Comanche 2 is scheduled to run to 2025, and PSCo claims it does not reconsider economics or earlier retirement dates in the capital planning process. If PSCo then revisits its retirement schedule in 2020, the 2019 repairs would be sunk costs that should not factor into a retirement decision. In this hypothetical, if the need for major repairs meant that the right time to shut Comanche 2 were 2020, PSCo would never know it, since PSCo is unwilling to reconsider retirement options in its capital planning process, regardless of the magnitude of the capital expense, and regardless of how poor the economics of a unit are. And PSCo will seek to recover the unnecessary repair costs from ratepayers over the last few years of Comanche 2 operation.

Q: Are you are suggesting that PSCo should analyze the retirement option before committing to any capital expenditure, no matter how small?

A: No. Many, and perhaps most, capital additions are both small and expected. A reasonable economic analysis of a coal plant's viability would include expected capital expenditures. For example, if a unit is found in 2020 to be earn $15/kW-year of net benefits to customers, even after an average of $20/kW-year of capital additions, there would be no need for PSCo to analyze the cost-effectiveness of continued operation before making the expenditures assumed in that analysis, or unexpected costs that eat into the customer profits. But an additional capital expenditure of $50/kW would

eliminate over three years of customer benefits, indicating that PSCo should update the unit's economics before making that commitment. A capital project of $100/kW would eliminate almost seven years of benefit in this example, indicating that retirement is likely to be the lower-cost option.

Q: Has PSCo demonstrated the reasonableness of the requested 2019 capital additions in the Direct Testimony of Kyle Williams, as it claims?

A: No. At most, Mr. Williams has explained why he believes that a few of PSCo's capital expenditures were required to keep the power plants operating. He does not address whether the plants should have been kept in operation.

Q: Is PSCo's refusal to ever consider the economics of its coal plants during its capital planning process consistent with its stated commitments to environmental and affordability goals?

A: No. PSCo witness Brooke Trammel states PSCo's strategic priorities.

> Our strategic priorities are to lead the clean energy transition, enhance the customer experience, and keep customer bills low. These priorities manifest themselves in this rate review filing and everything we do here in Colorado. We want to be responsive to the needs and desires of our customers by continually evolving and improving the customer experience, increasing clean energy, and reducing carbon emissions without losing sight of our core competency – safely delivering reliable and affordable electricity supply to customers. (Tramell Direct Testimony at 29)

She also mentions that Xcel "would seek to reduce carbon emissions by 80 percent from 2005 levels by 2030 and 100 percent from 2005 levels by 2050." (*Id*. at 30). In discovery, PSCo claims that its "vision is to keep customer bills low while leading the clean energy transition and continuing the industry-leading movement towards a clean, reliable and affordable generation mix." (PSCo Response to Discovery Request LWG2-5(d)).

Leading the clean energy transition moving towards a clean generation mix, while maintaining affordability, must include carefully monitoring the economics of its coal units and retiring them promptly if they are uneconomic, to avoid unnecessarily high bills and unnecessary emissions. PSCo's policy regarding capital planning means that it ignores costs and emissions for long periods of time.

Moreover, PSCo refused to even discuss how its decisions about capital investments and maintenance for its coal units are consistent with its carbon reduction goals. For example, PSCo refused to provide any substantive response to either of these questions:

- "Please provide all Xcel or PSCo formal policies related to capital expenditures for existing coal and natural gas plants in light of Xcel's carbon reduction goals." (Discovery Request LWG 9-1).
- "Please provide all Xcel or PSCo correspondence related to whether to make capital expenditures for existing coal and natural gas plants in light of Xcel's carbon reduction goals." (Discovery Request LWG 9-2).

In both cases, PSCo claims to have lofty ambitions, but refuses to even discuss how its capital planning process is achieving those ambitions. In a continuation of its

misguided view of the planning process, PSCo responds to these questions by claiming that explaining how it incorporates those goals in its planning "is not within the scope of the Company's requested rate review and therefore irrelevant." (e.g., PSCo Responses to Discovery Requests LWG 9-1, 9-2, 9-3).

Q: How should the Commission respond to PSCo's failure to consider the economics of continued operation, to accept responsibility for minimizing customer costs, or to provide any documentation of how its capital planning achieves its stated carbon reduction goals?

A: The Commission should clarify PSCo's responsibility for prudently managing its power supply and minimizing costs, including capital costs. The Commission should also require that PSCo justify its capital expenditures at each of its coal units, starting with Hayden and Craig, and should require that PSCo explain how it is embedding its strategic priorities, particularly its carbon reduction priorities, in its capital planning process.

VI. Conclusions and Recommendations

Q: Please summarize your conclusions.

A: As discussed above, I conclude that:

- PSCo has not demonstrated the prudence of its handling of the Comanche 3 superheater failures.
- Strong evidence suggests that the Hayden and Craig coal units, and potentially other PSCo coal units, are uneconomic and unnecessarily burden consumers.
- The economics of coal plants have generally been deteriorating in the face of low costs for market purchases and new renewables, and PSCo should be carefully monitoring the continued viability of all of its coal units.
- PSCo has not been systematically monitoring the economics of its coal plants or considering retirement options in the capital planning process.

Q: Please summarize your recommendations.

A: I recommend that the Commission:

- Disallow the capital costs of the Comanche 3 superheater tube failures, unless PSCo can rebut the evidence of imprudence that I present above.
- Disallow and/or require PSCo to refund to customers the replacement power costs incurred as a result of the outages to repair and replace the superheater tubes, unless PSCo can rebut the evidence of imprudence that I present above.
- Require that, in its next resource plan filing, PSCo justify its decisions to keep each of its coal units on-line, starting with Hayden and Craig.
- Forcefully remind PSCo of its responsibility for prudently managing its power supply and minimizing costs, including in its capital planning process.

- Put PSCo on notice that no Craig or Hayden expenditures will be recoverable in the next rate case, unless PSCo demonstrates that the associated unit provides net customer benefits, compared to available replacement resources.
- Require that PSCo explain how it is embedding its strategic priorities in its capital and operational policies.

Q: Does this conclude your testimony?

A: Yes.