Exhibit D

STAFF REPORT

Volume I

Public Version

PROCEEDING NO. 20I-0437E

IN THE MATTER OF THE INVESTIGATION INTO THE HISTORY AND CONTINUING OPERATIONS OF THE PUBLIC SERVICE COMPANY OF COLORADO COMANCHE UNIT 3 GENERATING STATION PURSUANT TO DECISION NO. C20-0505.

March 1, 2021

COLORADO
Department of Regulatory Agencies
Public Utilities Commission

The observations, findings and recommendations included in this report are those of the Staff of the Commission participating in this investigation and are not to be construed as being the observations, finding or recommendations of the Colorado Public Utilities Commission or of any individual Commissioners.

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Staff also acknowledges the efforts of Public Service's regulatory team and counsel, which produced a tremendous number of records, responded to numerous interrogatories, and performed significant modeling and analyses in support of this investigation.

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List of Acronyms

ADIT – Accumulated deferred income tax
AF – Availability factor
AFUDC – Allowance for funds used during construction
AGC – Automatic generation control
AVR – Automatic voltage regulator
CF – Capacity factor
CPUC – Colorado Public Utilities Commission
COD – Commercial Operation Date
DA/RT –Day-ahead/real-time
DC – Direct Current
EAF – Equivalent availability factor
ECA – Electric Commodity Adjustment
EIA – U.S. Energy Information Administration
ERP – Electric Resource Plan
GADS – Generation Availability Data System
GE – General Electric
GWh – Gigawatt-hours
HP – High pressure
IP – Intermediate pressure
LCOE – Levelized cost of energy
LP – Low pressure
MCSA – Master Coal Supply Agreements
MMBtu – Metric million British thermal unit
MW – Megawatts
MWh – Megawatt-hours
NCF – Net capacity factor
NERC – North American Electric Reliability Corporation
NMC – Net maximum capacity
OJT – On-the-job training
O&M – Operations and maintenance
P&ID – Piping and instrumentation diagram
PSA – Plant Specialist Apprentice
PSCo – Public Service Company of Colorado
SPOF – Single Point of Failure
SCR – Selective catalytic reduction
SDA – Spray dryer absorber
SI – Structural Integrity Associates
SPOF – Single point of failure
TLO – Turbine lube oil
QA – Quality Assurance
WACC – Weighted average cost of capital

I. Executive Summary

The Colorado Public Utilities Commission ("Commission"), on October 30, 2020, issued Decision No. C20-0759 opening a non-adjudicated proceeding for the purpose of directing the Staff of the Commission to complete an investigation into the history and continuing operation of the Public Service Company of Colorado's ("Public Service," "PSCo," or "Company") Comanche Unit 3 generating station ("Comanche 3"). This report presents Staff's findings from its investigation to the Commission.[1]

The origin of the investigation is found in Proceeding No. 19AL-0268E, Decision No. C20-0505, where the Commission discussed a number of the continuing operations and equipment problems that have plagued Comanche Unit 3 since it was declared as a used and useful on May 8, 2010 and in commercial operation on July 6, 2010. The specific incidents that the Commission discussed in the decision included: the boiler tube leaks encountered in late 2009 that Public Service indicated were due to inadequate post weld stress relieving treatments; the stack noise issue; the reduced capacity factors due to planned outages required to correct improperly welded components in the boiler and unplanned outages as a result of slagging due to malfunctioning water cannons; the replacement of the finishing superheater which was the subject of a recommendation to disallow recovery of $11.7 million in investments; and finally, the extended outage that began in January of 2020 to repair and replace steam turbine blades. Subsequent to the referenced decision, a second major incident occurred at Comanche 3. At the completion of the January 2020 outage, a loss of lubrication to the main turbine shaft while in the process of returning the unit to service resulted in extensive damage to the turbine, generator and ancillary equipment. This outage extended beyond the end of 2020.

The investigation into the history and ongoing operation of Comanche 3 by the Commission's engineering and economics Staff resulted in the following observations:

1. General Electric reported that "[redacted]"
2. Structural Integrity Associates reported that [redacted]

[1] This report is labeled as Volume I. The audit responses and attachments referenced in this report are compiled as Volume II, which is entirely confidential.

3. The poor maintenance practices likely contributed to the January 13, 2020 outage where major turbine repair and renovation activities were required to return the plant to service;
4. Unidentified equipment defects, inadequate equipment marking, insufficient communications protocols, lack of thoroughness in procedures and training, and human error contributed to the June 2, 2020 loss of turbine lube oil incident and outage;
5. The history of the plant for the period from Commercial Operations Date of July 6, 2010 through the end of 2020 revealed on average 91.5 days of outage each year with roughly 27 percent of the outages being planned, 24 percent associated with boiler tube leaks, and the remaining associated with other unplanned non-routine outages;
6. The availability and capacity factors of Comanche 3 dropped dramatically in 2020, at 4.03 and 2.37, respectively;
7. When compared to other PSCo-owned coal and gas-fueled units that operate on either a single steam cycle or a combined cycle, Comanche 3 had the lowest availability of all units from 2010 through October 2020, despite being the youngest unit.
8. The January 2020 low pressure turbine damage repair imposed significant costs including:
   - Re-blading of the turbine which was about a $4.8 million capital cost; and
   - Incremental replacement power costs for the lengthy outage estimated at about $1.7 million;
9. Costs stemming from the June 2, 2020 incident were even more significant and included:
   - Repair activities totaling $20.4 million in capital and O&M costs; however, PSCo expects all but the deductible and overhead (about $1.5 million) to be reimbursed by insurance;[2] and
   - Ratepayers incurred about $14 million in incremental power replacement costs, according to PSCo's simulations with the lengthy outage necessitating expensive short term market purchases during the summer peak period;[3]
10. The levelized cost of energy from Comanche 3 has been significantly higher than was anticipated when the unit was proposed in 2004;
    - The forecasted LCOE was $45.70,[4] while through 2020 the actual LCOE was $66.25/MWh;

[2] The insurance company's investigation is still ongoing.
[3] These replacement power costs are not covered by insurance.
[4] Confidential Response CPUC10-1f states that this was the LCOE estimate provided in Rebuttal Testimony in Proceeding No. 04-0214E. It is not directly comparable to the actual LCOE through 2020

- o There are multiple reasons for this higher cost; when compared to the original projections, Comanche 3 has experienced:
  - Higher initial capital costs,
  - Significant ongoing capital costs that appear to have been excluded from the original projections,
  - Higher O&M costs, and
  - Lower availability and therefore lower production; and

11. Comanche 3's net amount in PSCo's rate base was $885 million in 2010. It has declined to $633 million in 2020 and Staff projects, assuming continuation of historic trend information, it will further decline to about $460 million in 2030, $389 million in 2035, and $320 million in 2040.

because it included $73.3 million associated with the emissions control upgrades at Comanche 1 and 2 and represented the levelized cost for the assumed life of the plant rather than the first ten years.

II. Issues Investigated

A. Commission Directives

The Commission, in Decision No. C20-0759, directed that the issues to be investigated shall include, but not be limited to the following:

a) The Company's root cause analysis of the incident on or about June 2, 2020 where the loss of lubricating oil for the steam turbine main resulted in major damage and an extended outage for Comanche Unit 3;
b) Corrective actions being implemented to prevent recurrence of a similar event;
c) Adequacy of and compliance with the lockout-tagout procedures that apply to the equipment and actions taken during the June 2, 2020 event;
d) Adequacy of training programs as they apply to the actions taken by plant personnel during the June 2, 2020 event;
e) Estimated capital cost for repair of damages incurred as a result of the June 2, 2020 incident;
f) Estimated cost of replacement power incurred as a result of the June 2, 2020 incident;
g) Chronology of major planned and unplanned outages and major de-rates since the beginning of commercial operations on July 6, 2010 and identify chronic issues causing outages or derates;
h) Root cause of outages identified in g) above;
i) Corrective action taken (i.e., changes on operations, materials selection, etc.) to prevent reoccurrence for each of the outages identified in g) above;
j) Incremental capital expense incurred to repair or replace damaged equipment for each outage identified in g) above;
k) Impact on coal supply contracts;
l) Availability of the unit as compared to similar coal-fired generating units;
m) Actual capacity factors to date as compared to projected capacity factors since commercial operation on July 6, 2010;
n) Incremental capital investments projected at the time of approval of the unit as compared to actual incremental capital investments;
o) Capital expenses incurred to replace or repair equipment recovered from manufacturers or vendors under warranty, if any;
p) Estimated cost of replacement power for plant availability that is less than projected or due to unplanned outages or de-rates; and
q) Estimated levelized cost of energy for the first ten years of operations.

The Commission further directed Staff to consider and investigate other related issues that may arise during the investigation.

B. Report Organization

To report Staff's observations, findings, and recommendations, the specific issued identified by the Commission above were organized under the following primary topics:

- **Year 2020 Incidents**
  - The likely root causes and recommended corrective actions associated with the January 13, 2020 outage.
  - The Company's root cause analysis of the incident on or about June 2, 2020 where the loss of lubricating oil for the steam turbine main resulted in major damage and an extended outage for Comanche Unit 3;
  - Corrective actions being implemented to prevent recurrence of a similar event;
  - Adequacy of and compliance with the lockout-tagout procedures that apply to the equipment and actions taken during the June 2, 2020 event; and
  - Adequacy of training programs as they apply to the actions taken by plant personnel during the June 2, 2020 event;
- **Cost of the 2020 Incidents**
  - Estimated capital cost for repair of damages incurred as a result of the June 2, 2020 incident;
  - Estimated cost of replacement power incurred as a result of the June 2, 2020 incident;
- **Performance History**
  - Chronology of major planned and unplanned outages since the beginning of commercial operations on July 6, 2010;
  - Incremental capital expense incurred to repair or replace damaged equipment for each outage identified in (g);
  - Capital expenses incurred to replace or repair equipment recovered from manufacturers or vendors under warranty, if any;
  - Estimated cost of replacement power for plant availability that is less than projected or due to unplanned outages or de-rates;
  - Root cause of outages;
  - Corrective action taken (i.e., changes on operations, materials selection, etc.) to prevent reoccurrence for each of the outages identified in g) above;
  - Availability of the unit as compared to similar coal-fired generating units; and

- Actual capacity factors to date as compared to projected capacity factors since commercial operation on July 6, 2010;

- **Overall Costs Compared to Original Expectations**

  - Estimated levelized cost of energy for the first ten years of operations;
  - Incremental capital investments projected at the time of approval of the unit as compared to actual incremental capital investments;
  - Operations and Maintenance (O&M) expenses_projected at the time of approval of the unit as compared to actual O&M;
  - Impact on coal supply contracts;

- **Implications in Future Regulatory Proceedings**

  - Modeling in 2021 Electric Resource Plan and Clean Energy Plan proceeding;
  - 2020 Electric Commodity Adjustment (ECA) Prudence Review;
  - Phase I Electric Rate Proceeding;
  - Future depreciation studies;
  - Comanche 3 Follow-up

III. Year 2020 Incidents

There were two major incidents that occurred in 2020. The first was an outage that began on January 13, 2020, when the Comanche 3 turbine experienced a step change in vibrations after a loud noise was observed coming from the second low pressure turbine which signified significant equipment issue. The unit was out until June 2, 2020 to complete the necessary inspections, repairs, and reassembly of the unit. The second incident occurred on June 2, 2020 when Comanche 3 was in startup following the extended steam turbine outage when the turbine lube oil system (TLO) system was unintentionally isolated, resulting in damage to the steam turbine bearings Babbitt and significant damage to the turbine and generator equipment. The second outage extended through the end of 2020.[5]

A. General Description of Comanche 3 Turbine and TLO System

Comanche 3 has a supercritical Mitsubishi TCRF36, N-61 steam turbine generator set.[6] The 750 MW nameplate steam turbine generator set is so large that it was not designed using a single turbine/generator shaft as a rotor. Instead, the Comanche 3 turbine generator utilizes a combination of three large rotors coupled together: a shaft for the combined nine-stage high pressure (HP) turbine/six-stage intermediate pressure (IP) turbine coupled to two shafts operated in tandem that serve two six-stage dual flow low pressure (LP) turbines. In addition, the low pressure B side is coupled to an 829 MW MELCO hydrogen cooled generator.[7] Figures 1 through 3 below show Comanche 3's HP-IP rotor and the two LP rotors.

[5] The Company reported in its Second Supplemental Confidential Response CPUC8-23 that "Comanche 3 returned to service at 01:44 MST on January 19, 2021 and has been in continuous operation since that time."
[6] Theoretically, a supercritical power plant has a greater thermal efficiency than a conventional plant. This is because the water involved in the process operates at pressures and temperatures above its thermodynamic critical point, meaning the water transitions instantaneously from a liquid state to a fully gaseous state (no boiling or vapor phase).
[7] Confidential Attachment CPUC2.2b.A4, p. 2.

Figure 1. Comanche 3 high pressure, intermediate pressure (HP-IP) rotor.

Figure 2. Comanche 3 low pressure A (LPA) rotor.

Figure 3. Comanche 3 low pressure B (LPB) rotor.

Rotating shafts on turbine generators must have active lubrication in all phases of operation (e.g. in-service and standby). Lube oil acts to minimize friction that causes overheating in bearings and journals where there are metal-on-metal contact surfaces between the rotating element and turbine housing. This makes the turbine lube oil (TLO) system critical to the operation and well-being of the turbine and the associated generator/exciter equipment.

A small interruption of the lube oil to the turbine can cause catastrophic damage. Every TLO system has a large tank that acts as a reservoir for pumps that circulate lube oil to and from bearings and journals via a circular system of valves and piping. Key to the function of the turbine lube oil system is the ability to remove small particles of metal that become entrained in the oil from bearing wear. Thus, TLO systems have lube oil strainers or filters that remove particles that require regular changing and servicing. In addition, the heat that the lube oil picks up as it passes through bearings must be removed before that same oil is passed through the bearings again. To do this, heat exchanges are included in the system. Normally, a TLO system consists of a lube oil tank, two main lube oil pumps (A & B), an emergency backup lube oil pump, and ancillary equipment needed to maintain the function of the system including transfer valves, filters (strainers), and turbine lube oil coolers to maintain constant temperature. A typical flow diagram of a TLO system is shown in Figure 4.

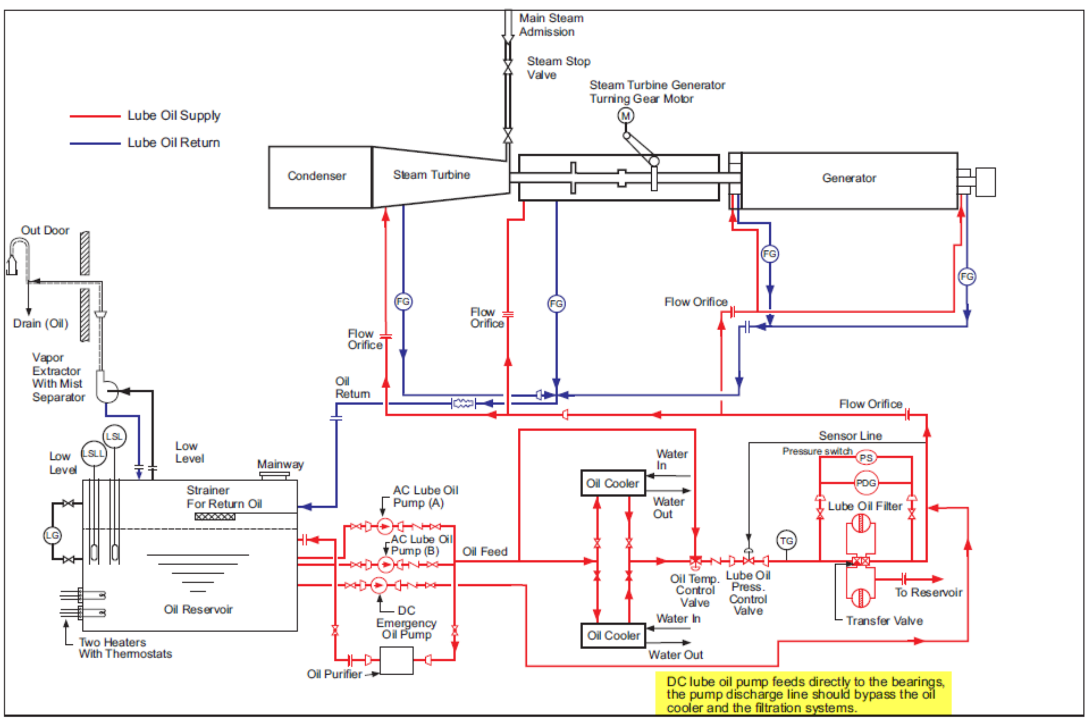

Figure 4. Typical steam turbine lubricating system. [8]

[8] FM Global Property Loss Prevention, Data Sheet 13-3, Steam Turbines, January 2013, Fig. 4.

To understand the TLO system incident that occurred at Comanche 3 on June 2, 2020, it is important to have a basic understanding of how the TLO system was designed and operated. The unit's main TLO pumps A & B can be operated individually or in tandem and direct the flow of lube oil through one or both trains of piping/processing equipment (A & B) via the operation of a one six-way transfer valve. The six-way transfer valve directs the flow of lube oil from the main oil tank through piping and oil processing equipment through the A train, the B train, or both. The emergency direct current ("DC") lube oil pump operates as a backup in case the main lube oil pumps A & B are not operational. The lube oil from the emergency pump flows through the same piping trains as the two main lube oil pumps A & B. It also flows through the singular 6-way transfer valve.

The most important take away from this discussion is that the configuration of the Comanche 3 TLO system at the time of the incident relied on a single six-way transfer valve, regardless of whether the main TLO pumps or the emergency DC pump was operating. As a result, a misconfiguration of the six-way transfer valve eliminates either the main pumps or emergency pump from providing necessary lubricant to the steam turbine to prevent overheating.

B. January 13, 2020 Outage

A full train inspection of the steam turbine was planned for the fall of 2020, but Comanche 3 was removed from service on January 13, 2020 to investigate a step change in and noise was observed coming from the Low Pressure Turbine B. This indicated a significant equipment issue and initiated the January 2020 forced outage. Inspection of the turbine revealed rubbing on eight of the high pressure rotating blade shrouds with work hardening on three of shrouds and a section of the shroud was missing. In addition, the inspection revealed significant seal damage in the lower portion of the casing.[9]

The detailed inspection and analysis of the condition of the turbine suggested that the high pressure turbine shaft and turbine casing was bowed from water induction into the turbine during two events in January and September of 2018. It's likely that damage occurred when the bowed shaft was rotated on the turning gear and during unit startup. Damage also likely occurred during a third event in December of 2018, a startup with excessive vibration from high eccentricity.[10] An example of the damage is shown in the figure below.[11]

[9] Confidential Attachment CPUC2-2b.A1, Confidential *Report on Comanche Unit 3 High Pressure Turbine Blade Damage*, Prepared by Elliot Hunt, Fleet Engineering., p.1.
[10] Ibid., p.6.
[11] Confidential Attachment CPUC2-2c.A2, *Comanche 3 Turbine Root Cause Analyses*, May 1, 2020, p.13.

Figure 5. HP turbine damage at 9th stage.

The Company engaged General Electric ("GE") as the contractor tasked with analyzing and repairing the damage to the turbine generator equipment. GE identified multiple areas of equipment concern that ultimately necessitated a 141-day outage to make repairs. GE's final report provided a summary of the major issues addressed, which included:

[redacted]

[redacted][12] and

- A TLO system flush was performed by a third party contractor during this outage as part of repair activities.[13]

The GE report executive summary included the following significant finding: "[redacted][14,15]

[redacted][16]

[redacted][18]

The Company also engaged the services of Structural Integrity Associates (SI) to investigate the mechanism and root cause of the L-1 turbine blade failure shown in Figure 5 below, and to assess the steam cycle chemistry for Comanche 3.[19]

[12] Confidential Attachment CPUC2-2b.A4, p. 276.
[13] Ibid., pp. 8-9.
[14] "Machine," as used in this context, refers to entire Unit #3 turbine generator assembly including ancillary equipment.
[15] In power engineering, "steam quality" is a thermodynamics term that refers to the mass fraction of a saturated mixture that is a vapor. For example, upon leaving a turbine, steam with a quality of 0.90 indicates the mixture is 90 percent vapor and 10 percent liquid by mass. If quality is too low, the wet steam can cause damage to the turbine.
[16] Confidential Attachment CPUC2-2b.A4, p.243.
[17] Ibid., pp. 202.
[18] Ibid., pp. 267-268.
[19] Confidential Attachment CPUC2-2b.A2.

Figure 6. Missing turbine blade of L-1 section of LH.[20]

The company also engaged a consultant to assess whether steam cycle chemistry contributed to the blade damage show in the figures below.[21]

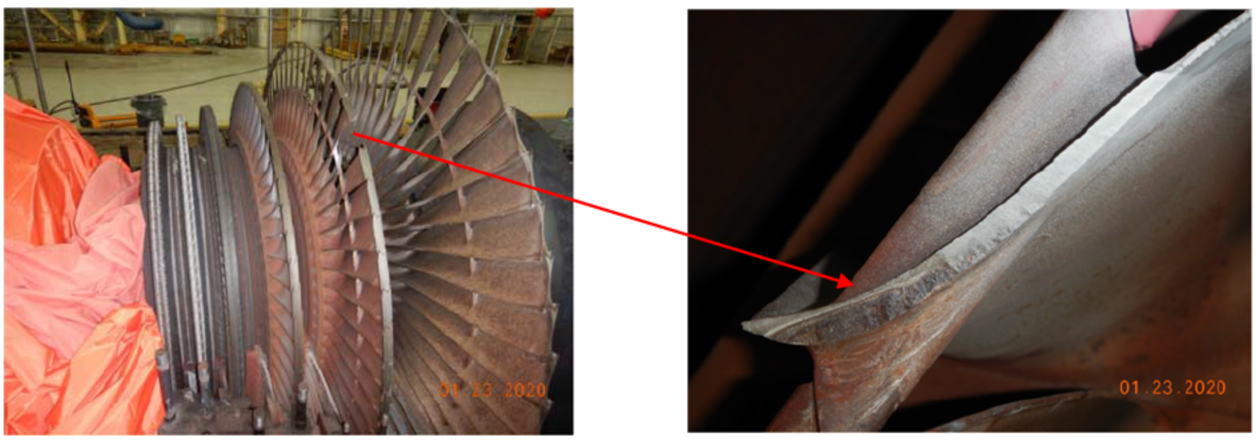

Figure 7. Blade damage.

[redacted]

[redacted]

[20] Confidential Attachment CPUC2-2b.A4,p. 26.

[21] Confidential Attachment CPUC2-2b.A3, *Comanche Unit 3 LP Turbine, L-1 Blade Cracking, Preliminary Report*, January 31, 2020, p. 2.

[redacted][22]

[redacted]

[redacted][23,24]

[redacted]

[22] Confidential Attachment CPUC2-2b.A2, p. 3.
[23] Ibid., p. 10.
[24] [redacted]; the Company provided the *Comanche Unit 3 Chemistry Manual, June 2020, Revision 1.1* in response to Audit Request CPUC18-1. In addition, the Company represented that this is the 5th revision of the manual since 2010 with a 6th revision in process.

[redacted]

[redacted]

[redacted][25]

Comanche 3 was in an outage state for 141 days returning to service on June 1, 2020. It was during unit startup at the conclusion of the turbine blade replacement and repair outage that the turbine lube oil event occurred.

Staff documented approximately $4.8 million in capital costs for this turbine blade replacement allocated to PSCo's ownership share. Furthermore, an estimated $1.7 million in incremental replacement power costs were incurred during this extended

[25] Confidential Attachment CPUC2-2b.A2, pp. 11-12.

outage, as PSCo had to produce or purchase more expensive energy with Comanche 3 offline.

C. June 2, 2020 Outage

In its initial root cause analysis provided to the Commission on October 8, 2020,[26] the Company indicated that on the afternoon of June 2, 2020, the Comanche 3 turbine was approaching the speed needed to begin synchronizing the unit into the transmission grid. During synchronization, the Control Room received a high TLO temperature alarm and the Comanche 3 Control Specialist made the decision to trip the turbine.

While the turbine began spin down, a team consisting of Comanche's Senior Operations Manager (i.e., the Plant Manager), the Operations Manager, and two higher level operators (a Plant Specialist 2 and a Plant Specialist 3) attended to the TLO coolers to troubleshoot. Noteworthy was the fact that the Plant Specialist Apprentice 1 ("PSA1"), who was designated to operate the Comanche 3 TLO equipment during the unit startup, was not part of this team. Upon arrival, the team found that both TLO coolers were in operation but noted "higher TLO temperatures on the west cooler through touch." The Senior Operations Manager then directed a Plant Specialist (other than the assigned PSA1) to operate (i.e., open or reposition) the six-way valve on the oil side of the west cooler, and the oil temperature on that cooler began to significantly drop. The change to the TLO system configuration was communicated to the Control Room, but not to the PSA1 who was designated in charge of operating the TLO system equipment. The Comanche 3 turbine was then spun up and re-latched, and operations personnel proceeded with startup procedures.

After addressing the TLO temperature issue, one of the Plant Specialists who had been involved with changing the TLO valve configuration had a brief discussion about the changed configuration with the PSA1 designated to operate the TLO system equipment during the startup. Unfortunately, they discussed the water side of the cooler configuration, but not changes in the configuration made on the oil side. The PSA1 designated to operate the turbine was not satisfied with the explanation provided by the other Plant Specialist and as a result returned to the TLO coolers to explore the situation further. Upon arrival at the TLO skid, the PSA1 used his hand to determine TLO piping temperature and "in his opinion it felt cooler than it should have." The PSA1 also noted that there had been a TLO flush done during the outage and it was unclear whether contract personnel had operated TLO valves and whether TLO valves were positioned or repositioned during the outage.[27]

Troubleshooting the situation, the PSA1 noted the oil side TLO cooler configuration was in his opinion "abnormal," and he made corrections to the TLO cooler six-way

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[26] General Audit, Confidential Attachment CPUC17-1, Attachment A.
[27] Confidential Attachment CPUC1-2.A1, p. 2, ¶3.

valve on the oil side by attempting to adjust oil flow. The PSA1 rotated the six-way valve 180 degrees, which inadvertently starved the turbine bearings completely from all lube oil flow.

The Company's root cause analysis of the June 2, 2020 incident identified a single point of failure ("SPOF") on the lube oil system along with several contributing factors. The root cause analysis was limited to only a discussion of equipment concerns and determined the SPOF was caused by an unclear indication of position on the actuator of the TLO six-way valve near the turbine lube oil heat exchangers. Because the valve position indicator was unclear, the PSA1 who was designated to operate the turbine equipment during the startup operated the valve incorrectly and ultimately blocked all flow of lube oil to all turbine equipment.

The GE report also provided a summary of what occurred during the Comanche 3 startup that lead to the June 2, 2020 outage. [redacted]

[redacted]

[redacted].[31]

[28] Confidential Attachment CPUC2-2b.A4, p. 114.
[29] Ibid., p. 126.
[30] Ibid., p. 159.
[31] Ibid., p. 300.

[redacted]

The purpose of lubrication is to separate moving loaded surfaces by interposing an oil or grease film between the surfaces thereby reducing friction, heat, and wear. Without turbine lube oil flow, the surface of the turbine shaft and other components of the rotor train contacted the newly replaced bearing babbitt material on the turbine housing. The metal-on-metal contact overheated and marred the surface of the turbine shaft and steam seals. Large babbitt bearings that cradled the turbine shaft overheated, melted, and failed. Observers noted sparks coming from some of the turbine bearings and a flash fireball was seen coming from the top of the TLO tank.

Damage incurred during this incident required an additional 213-day outage of the 750 MW unit for a combined outage of 373 days.

D. Company Recommended Corrective Actions for June 2, 2020 Event

The Company's root cause analyst identified the following corrective actions:

- Visual indication will be provided via permanent labels and a pointer;
- Tactile indication will be provided by addition of a stop plate to the underside of the valve's actuator gear;
- Feedback indication will be provided by installation of a local oil pressure gauges; and
- Modifications will be made to the emergency backup oil supply in order to bypass the oil coolers and filters and their associated six-way transfer valve.

The root cause analyst also identified, but did not address that the design of the valve itself, the lack of adequate procedures and training to operate the valve, and the lack of adequate communication between the control room and operations staff were contributing factors that warrant corrective action. Considering that the six-way valve at issue is a complex, manually operated valve, it is essential to have detailed procedures, adequate training, and communications protocols in place between the control room and operations and maintenance staff.

E. Additional Company Investigations and Recommendations

The Company pursued a subsequent internal analysis of the incident using three management teams having different areas of focus: the Configuration Management Improvement Team, the Technical Improvement Team and the Human Performance Improvement Team.[32] The Technical Improvement Team and the Configuration Management Improvement Team were different from the Human Performance Team in that the first two teams were directed to develop and implement changes, whereas the later team was directed to make recommendations only.[33] A summary of each team's activities and recommendations is presented below:

i. Technical Improvements Team Recommendations

The Technical Improvement Team was directed to review the design of the Comanche 3 TLO system.[34] On June 29, 2020 the Technical Improvement Team released a document entitled "Root Cause Investigation Report" that presented key findings associated with the Company's internal investigation of the equipment involved in this incident.[35] The report addressed three primary areas of concern: equipment design; labels, signs and displays; and absence of indication/instrumentation. A discussion of these three areas of concern and the corrective actions implemented by the Technical Improvement Team follows.

a. Equipment Design

[32] General Audit, Confidential Attachment CPUC17-2.
[33] Confidential Audit Response CPUC 13-4.
[34] Confidential Attachment to CPUC13-4.A2.
[35] General Audit, Confidential Attachment CPUC17-1.

- *Correct TLO Cooler 6-Way Valve Actuator Design.* The turbine lube oil temperature and quality are controlled by regulating the flow of oil through a plate and fin heat exchanger and strainer element. Having clean lube oil at the proper temperature is critical to safe turbine operation. In addition, the criticality of the TLO system necessitates redundancy.

  It was noted that the original piping TLO piping design, with a single transfer valve, is contrary to recommended best design practices which recommends that design "[e]nsure the emergency lube oil system configuration is inherently resilient and that no single failure can result in a loss of equipment lubrication. Ensure the emergency oil bypasses coolers and filters and feeds the bearings directly."[36]

  Consistent with best design practices, most large turbines having TLO systems have two heat exchangers and two lube oil strainers. The piping and valve configurations required to provide this redundancy is complex to design and costly to install. On the Comanche 3 turbine, the original piping designers chose to employ a singular unique valve assembly called a TLO Cooler 6-Way Transfer Valve which is shown below:

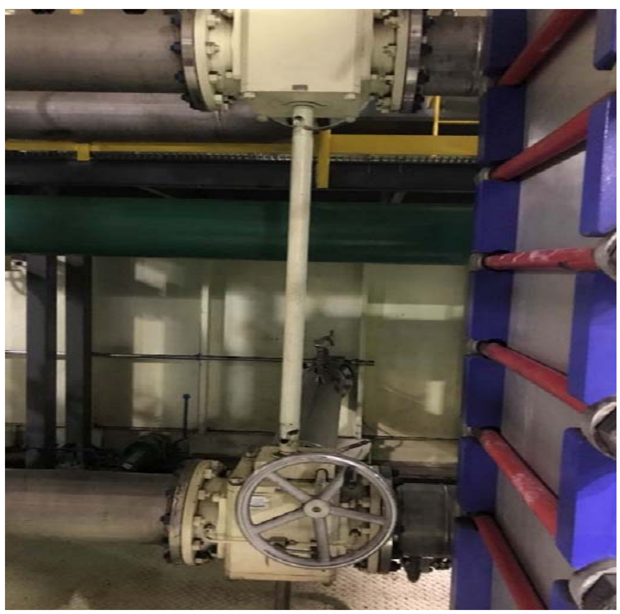

Figure 10. TLO cooler 6-way transfer valve. [37]

  The Comanche 3 TLO Cooler 6-Way Transfer Valve was manufactured by Indufil and enables continuous operation of one train (A or B) while allowing

[36] FM Global Property Loss Prevention, Data Sheet 13-3, Steam Turbines, January 2013, Section 2.1.3.1.4.
[37] Confidential Attachment CPUC1-1d.A1.

the other train to undergo maintenance such as filter changes. Indufil has since been absorbed by John Crane, which no longer supports this particular valve and has classified it as obsolete. Thus, the Company knows it cannot get replacement parts for the TLO Cooler 6-Way Transfer Valve. The Company has no policy with regard to the use of obsolete equipment in the power plant. Instead the Company explains that each piece of equipment is evaluated on its condition and maintainability. If parts are not available, or if repair costs are substantial, then Company will consider replacement of the equipment with an updated design.[38]

The Technical Improvement Team evaluated the TLO Cooler 6-way Transfer Valve and identified equipment damage based on design flaws in the valve's actuator. Specifically, the design for the valve master actuator worm gear stop pin (dowel pin) was determined inadequate (i.e., the original carbon steel material and 10mm pin size was undersized) and, as a result, sheared off at some unknown point in time during prior operation.[39]

Figure 11. Stop pin (red arrow) found under gear (green arrow). [40]

Because the stop pin was sheared, the actuator was able to rotate the valve's in-stream element (i.e., ball or plug) to a position which eliminated all TLO flow to the turbine bearings. To inspect or repair stop pin, the valve actuator

[38] Confidential Response CPUC13-9.
[39] Indufil six-way transfer valve manufacturers drawings, provided off John Crane Website.
[40] Confidential Attachment CPUC1-1.A3, Fig. 4.

must be disassembled as this stop pin is located underneath actuator gear. Because of location of the pin below the gear, the valve would have to be out of service (i.e. under lockout tag out control) to inspect and repair the pin. The valve could only be out of service if the turbine lube oil system was out of service. Upon disassembly of the valve, the sheared stop pin was discovered laying loose under the gear. Figure 10(a) shows the broken stop pin (red arrow) and the sheared off section of stop pin (green arrow) in the valve body. Figure 10(b) shows the underside of the gear shows circular collar (green) with a 180-degree collar section (red) which butts against the stop pin to prevent over-travel.

Figure 12 (a) *Gear removed.*[41]

Figure 10(b) *Underside of gear.*[42]

- *TLO Cooler 6-Way Valve Master Valve Actuator Design.* The master actuator did not have adequate visual indication of the relative position of its in-stream element as shown below.

[41] Ibid., Fig. 5.
[42] Ibid., Fig. 6.

Figure 13. Sharpie inscribed 6-way transfer valve position indication as found. [43]

The Technical Improvement Team corrected the inadequate visual indication position on the valve actuator by replacing the existing square shroud, with a rounded "nub" indicator and no signage, with a circular plat and "notched" indicator with plastic labeling as show below.

Figure 14. 6-way valve position indicator as modified.

- *TLO Cooler TLO Backup Source.* The TLO Cooler 6-Way Valve was the single point of failure for the June 2, 2020 incident. When the valve stop pin failed, it allowed plant personnel to position valve such that it isolated TLO flow to critical turbine components and also isolated TLO flow from the emergency backup TLO pump.

  As mentioned earlier, the original piping design which did not provide the ability for lube oil provided by the DC emergency oil pump to bypass the TLO coolers and filter sets is contrary to industry best practices which recommends

[43] Ibid., Fig. 2.

that the design "[e]nsure the emergency lube oil system configuration is inherently resilient and that no single failure can result in a loss of equipment lubrication. Ensure the emergency oil bypasses coolers and filters and feeds the bearings directly."[44]

The Technical Design Team, as part of the TLO system corrective actions, removed a section of pipe and added additional piping allowing the DC emergency TLO pump to bypass cooler/filters and feed directly to bearings. Figure 13 illustrates the redlined piping and instrumentation diagram (P&ID) of the system.

[44] FM Global Property Loss Prevention, Data Sheet 13-3, Steam Turbines, January 2013, Section 2.1.3.1.4.

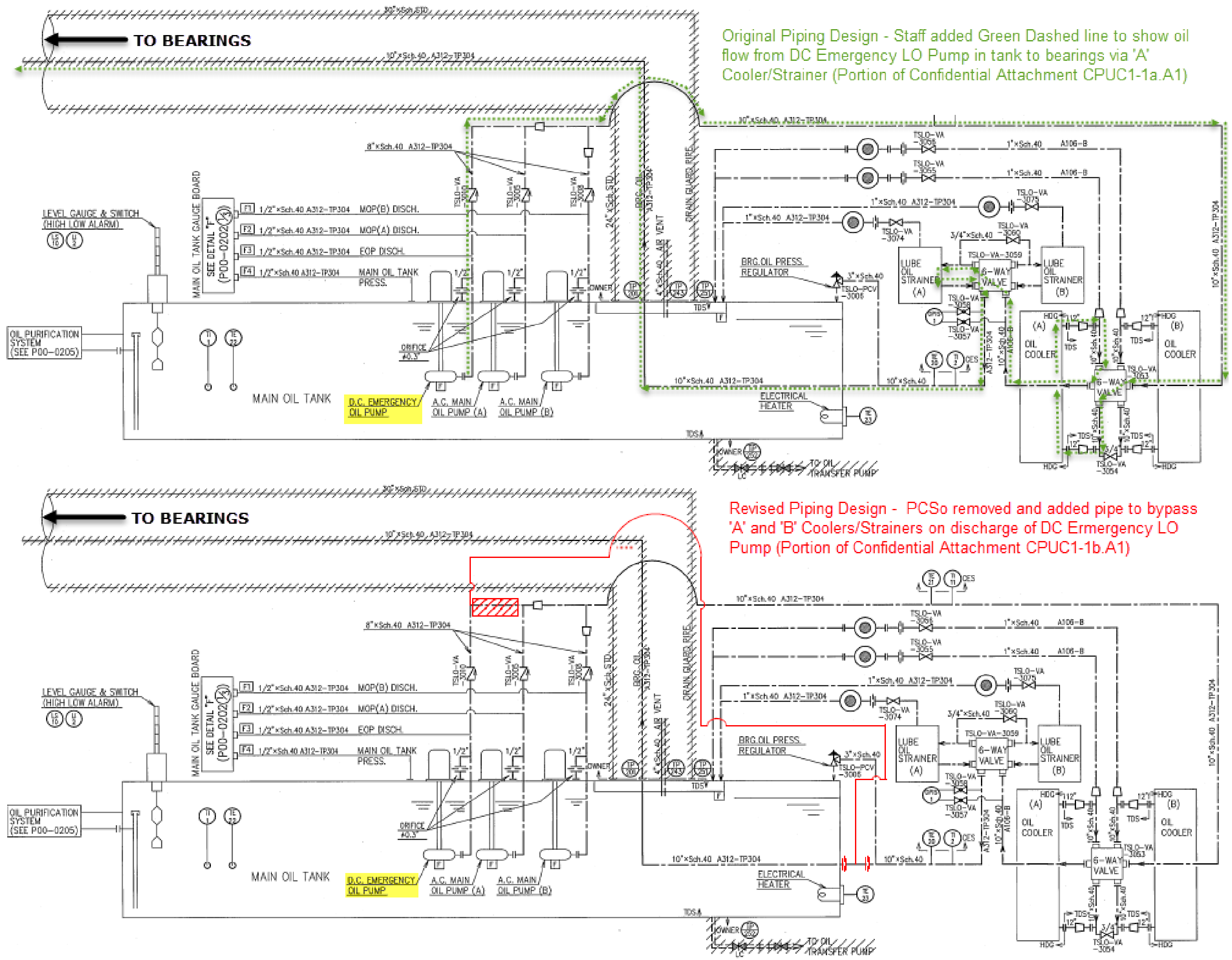

Figure 15. Original P&ID of lube oil system (top) vs. revised P&ID (bottom).

b. Labels, Signs and Displays

- *Valves did not have labels for every possible operating state (A, B, or A+B).* The TLO Cooler 6-Way Valve's master actuator, shown in Figure 11 above, did not have any understandable labels or indications for valve positioning other than labeling that several small, non-descriptive symbols – hand-scribed small blue arrow and some directional arrows. These markings do not clearly indicate the line-up of the coolers nor do they indicate the direction of flow.[45] The technical Improvement team felt the installation of plastic signage on the top of the actuator and yellow paint markers were appropriate for operator information in the future. See Figure 12 above.

c. Absence of Indication/Instrumentation

- *No local pressure or flow instrumentation to provide indication that oil was flowing in direction intended.* The Technical Improvement Team also stated they installed additional differential pressure indication on the Turbine Lube Oil system. Corrective actions listed in the root cause analysis document mention the recommendation for the installation of local oil pressure gauges, but these changes are not shown on the redlined P&ID drawings. As a result, there was no ability to verify whether the additional instrumentation adequately addressed the concerns associated with the TLO six-way valve.

ii. Human Performance Improvements Team Recommendations

Subsequent to the findings in the Root Cause Investigation Report, the Company also convened a team to examine contributing factors that were process and personnel related. Unlike the other internal teams created for analysis of this issue, the Human Performance Improvement Team was not charged with implementing their recommendations. It appears that decisions to act on the recommendations of the Human Performance Improvement Team were left to Company management discretion.[46] To date, the Company has provided very generalized responses as to how it is addressing the findings and recommendations made by the Human Performance Improvements Team.[47] It has not provided specificity with regard to how each specific finding or recommendation has or will be addressed.

The final recommendations made by the Human Performance Improvements Team, titled as the "Human Performance Team Analysis,"[48] [redacted] While the entire report is too long to discuss within the body of this report, [redacted]

[45] Confidential Attachment CPUC1-2.A1, p. 3.
[46] Confidential Response CPUC13-4.
[47] Confidential Responses CPUC13-15, CPUC13-16 and CPUC 13-17.
[48] Confidential Attachment CPUC1-2.A1.

[redacted]

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[49] Extent of conditional evaluations are usually completed soon after an accident to identify the presence of similar conditions across the organization such as looking for similar equipment or conditions.

[redacted]

iii. Configuration Management Improvement Team Recommendations

The Configuration Management Improvement Team's mission was to "implement a configuration management philosophy and process."[50] More specifically the team deliverables were:

- Complete a Lube Oil Valve Alignment Checklist.
- Complete a Seal Oil Valve Alignment Checklist.
- Develop a procedure for Equipment Manipulation and Status Control.
- Complete the Closed Cooling Water System Checklist.

The Company provided the following newly created operating procedural documents that did not exist prior to the occurrence of the incident:[51]

- COOP-3-00-001- Equipment Manipulation and Status Control;
- COOP-3-00-001- Comanche Unit #3 Chemistry Manual;
- COOP-3-CSUC-001- Unit #3 Pre-Start Configuration Management;
- COOP-3-AXNI-002- COMANCHE 3 Boiler Layup with Nitrogen;
- COOP-3-AXNI-002- COMANCHE 3 DA & HP Feedwater Heater Layup with Nitrogen;
- COOP-3-CSUC-000- Unit #3 Comanche 3 Startup Process Map;
- COOP-3-CSUC-001A26- Comanche 3 Configuration Management Master Checklist;
- COOP-3-CSUC-002- Unit 3 Pre-Start Water & Steam;
- COOP-3-CSUC-003- Unit 3 Pre-Start Pre-State Air; and
- COOP-3-CSUC-004- Unit 3 Pre-Start Turbine.

In addition, the following procedural documents were rewritten:

- COOP-3-AXNI-001 Nitrogen Gas System Operation, and
- COOP-3-CSUC-005 Unit 3 Start Up

a. Inadequate Adherence to the Company's Quality Control Policy

There appears to be a lack in adherence to the Company's energy supply quality assurance standards. While these observations and concerns relate to the Technical Improvement Team, the same concerns exist for other activities of energy production as demonstrated by the findings of the Human Performance Improvement Team.

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[50] Confidential Attachment CPUC13-4A.1.
[51] Confidential Response CPUC13-1.

The Company's current Energy Supply Quality Assurance Manual (QA Manual)[52] was created in 2011 and remained static until 2018 when several small revisions were made. The QA Manual has broad application across energy supply activities including all engineering, design and modification activities. The processes and documentation associated with the design changes for the 6-way TLO valve actuator were used to assess whether the Company is adhering to its quality assurance program.

The Company's Quality Control Manual requires all engineering design and modification work meet the following Energy Production Quality Assurance requirements:[53]

- Engineering and design activities are carried out in a planned, correct, controlled, and orderly manner to ensure:
    - Applicable quality standards are specified and included in design documents;
    - Deviations from applicable standards are controlled;
    - Materials, parts, equipment and processes essential to the functional requirements of the materials, structures, components, products, and systems are reviewed for suitability of applications;
    - Interfaces of participating internal and external organizations are identified, controlled and coordinated for the review, approval, release, distribution, and revision of design documents;
    - Adequacies of designs are checked and verified by design review, alternate calculation methods, certified computer codes, and/or suitable test programs;
    - Design verifications are performed by individuals independent of those who performed the original design;
    - Design changes are subject to the same controls as the original document; and
    - Design documents include traceability of quality assurance requirements and design bases.

The Company's design modification drawings for the actuator modifications is provided below:[54]

[52] Confidential Attachment CPUC8-1e.A1
[53] Ibid., p. 9.
[54] Confidential Attachment CPUC13-3-A.1.

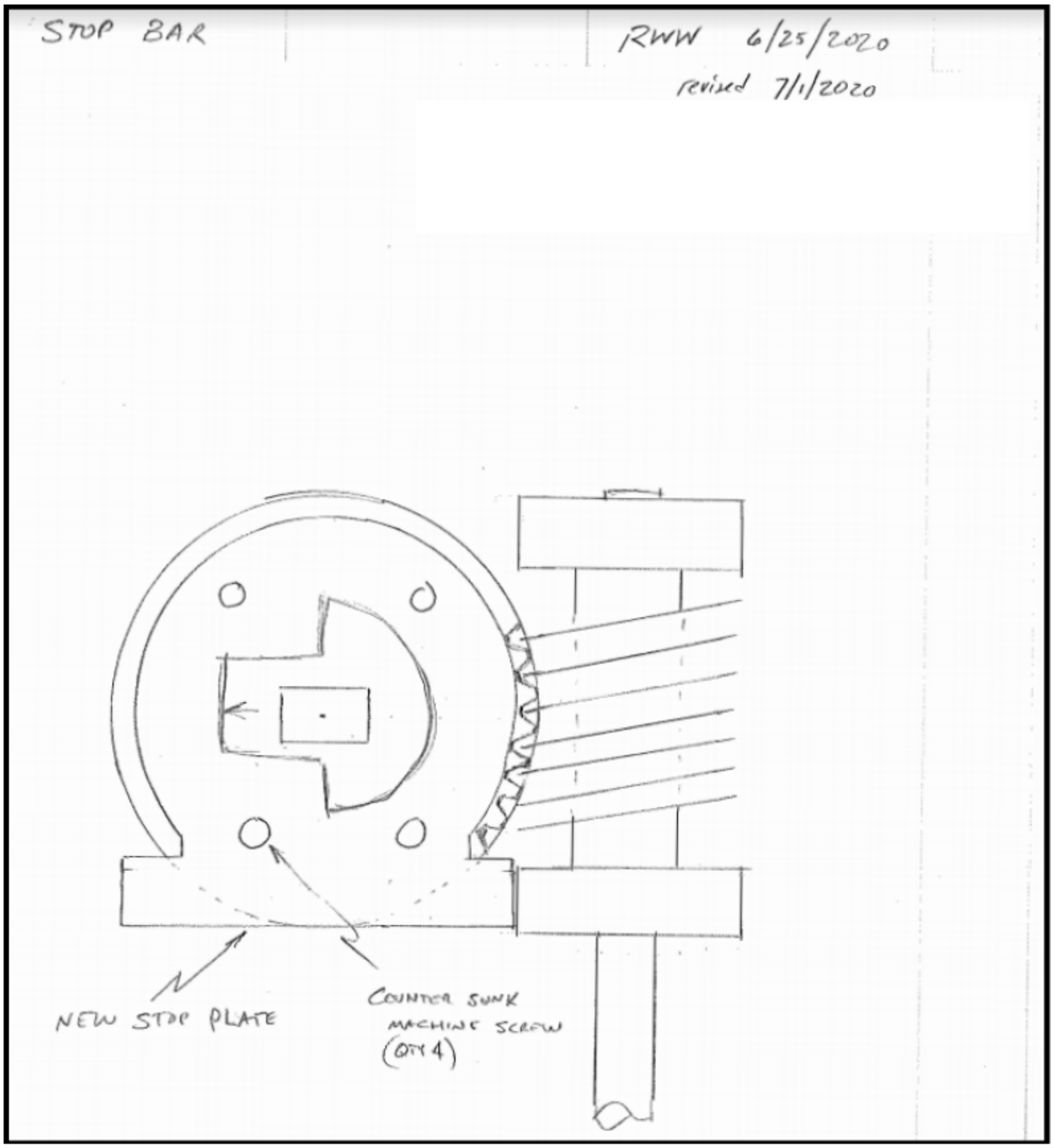

Figure 16. Valve sketch (1 of 2).

It was noted that the drawings were created and signed by the Technical Improvement Team Lead, who also happens to be the Plant's Manager of Reliability. There was no secondary or independent signature that demonstrated that the design was reviewed or verified. As is apparent by the single signature, design changes appear to have been made also without independent verification. There was no indication of the materials used for the modifications to the valve. There is no discussion of why modifications were made necessary (e.g. the result of a previous incident or identified by a SPOF analysis). There is no indication of what service standard was used, nor was there any indication that the drawings were filed or input into the plant's drawing system for future reference or traceability.

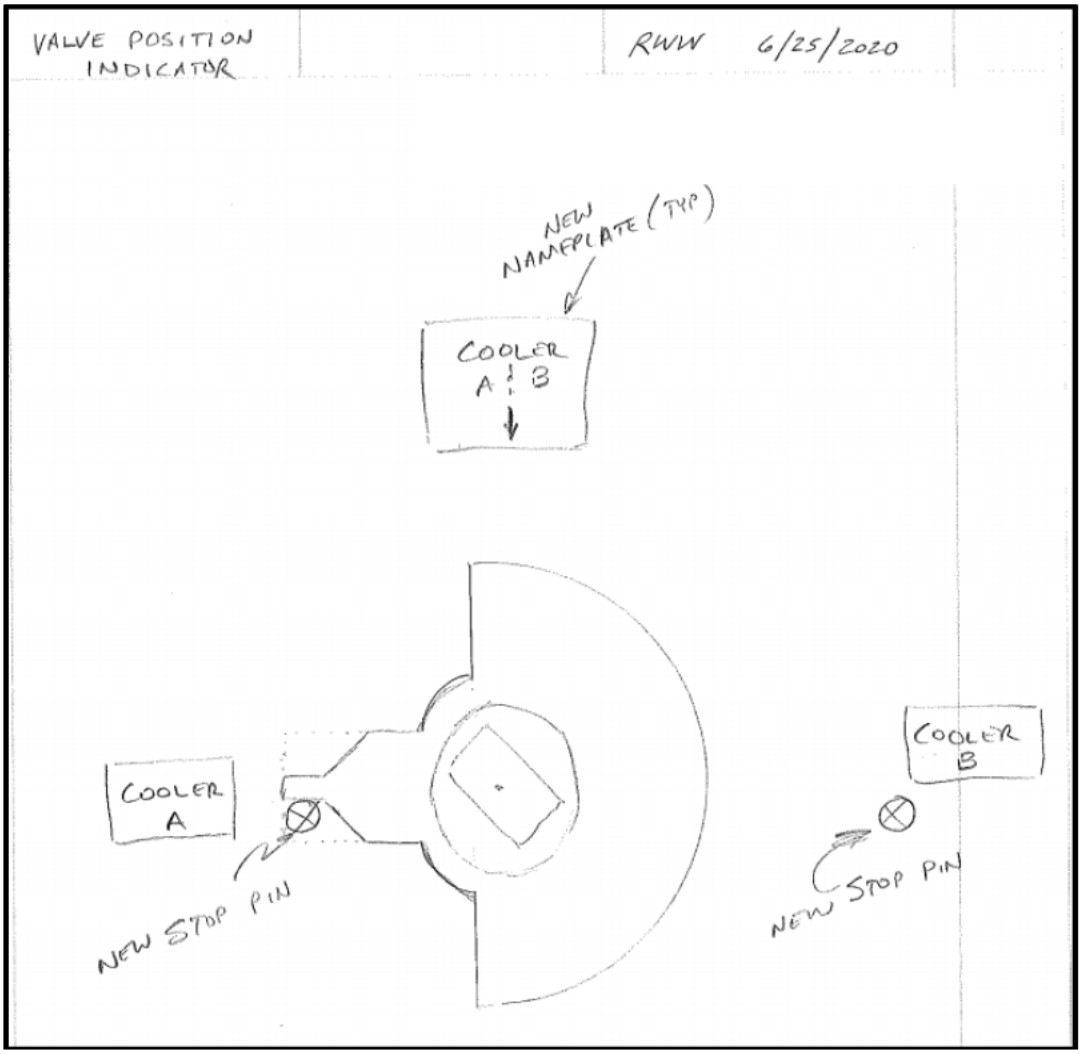

Figure 17. Valve sketch (2 of 2).

While this is may be a minor design change, it is essential to create a record of what modifications were made and why.

b. Lack of Appropriate Subject Matter Experts on the Team

The Technical Improvement Team states its directive was to "review the design of the COM3 lube oil system (currently normal AND emergency lube oil systems have a single isolation source) and the lube oil cooler 6-way valve […] to identify and mitigate vulnerabilities, reduce risk of catastrophic turbine/generator failure, and [c]omplete COM3 lube oil system modifications based on best practices."[55]. Although the Company had GE Services on retainer and still on site from the January 2020 Comanche 3 outage, the Company made the decision to limit Technical Improvement Team to four internal personnel. While the Company's Manager of Turbine Engineering was listed as being on the internal team, no document or drawing produced by the team had his name as participating or his signature as a reviewer

[55] Confidential Attachment CPUC13-4.A2.

(i.e., the root cause analysis listed only the Plant Manager of Reliability and the Cherokee/Valmont Plant Manager). The lead on the team was designated to be the Manager of Reliability, who the Company acknowledged had no previous experience modifying turbine lube oil systems.[56] Considering the magnitude of damage caused by the TLO system failure and the fact that the Company had GE Services on site, it is surprising that GE Services was not engaged to assist on the Technical Improvement Team.

c. Inadequate "Extent of Conditions" Analysis of Single Point Vulnerabilities

It is concerning that the Human Performance Team appeared to conclude that the primary cause for the accident was the improper change to the configuration of the TLO transfer valve and secondarily caused by a broken internal stop.[57] The root cause analysis did not discuss the design shortcomings of the Comanche 3 TLO system that prevented the DC lube oil emergency pump from providing lubrication to the turbine bearings when the TLO Six-Way Valve was misconfigured. Had this design shortcoming been identified and corrected to conform with industry best practices prior to the misconfiguration of the TLO transfer valve, the millions of dollars in turbine damage may have been prevented.

There should have been SPOF analysis performed on critical Comanche plant systems prior to the incident. A SPOF analysis is a formal process that determines the potential risks posed by a defects or system design deficiencies in which one fault or malfunction would cause the whole or larger system to fail.

SPOF analysis is not new to the power industry and there have been many accidents, including accidents on TLO systems that could have been prevented by a SPOF analysis. An example is the American Society of Mechanical Engineers, Power Conference, April 2005, case study that discussed malfunctions in the TLO system at San Onofre Nuclear Generating Station.

A SPOF analysis should be part of an overall program and structured methodology to identify and deliver the reliability, availability, and maintainability of a power plant [58] SPOF analyses should be performed on critical Comanche 3 systems to ensure safe operation and meet performance demands.

The Company acknowledged that it did not perform a SPOF analysis "for the plant or any of the processes that support the power plant."[59] It is troubling that the Technical Improvement Team whose Team lead, who is the plant's Manager of

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[56] Confidential Response CPUC13-3.
[57] Confidential Attachment CPUC1-2.A1, p. 1, ¶1.
[58] ASME RAM-1-2013 Reliability, Availability, and Maintainability of Equipment and Systems in Power Plants
[59] Confidential Response CPUC8-3.

Reliability, did not recognize this pre-incident deficit and perform the missing TLO system SPOF analysis prior to implementing modifications.

Considering that a formal SPOF study was not performed prior to the 2020 TLO incident,[60] it would be prudent to complete a SPOF analysis post-accident to assure that TLO system modifications mitigate a similar incident in the future.

d. Modifications Not Correct and Accessible to Other Personnel

Modifications made by the Technical Improvement Team were completed on July 6, 2020.[61] As of January 2021, the Company could not demonstrate that red lines on detail drawings had been incorporated into the plant's equipment drawing systems. Company policy on turnaround time for completion of redlines is within two months of project completion.[62] It is also unclear how the Company has or will formally document changes to the operating procedures as a result of this incident. There was no evidence that modifications had been incorporated into appropriate TLO operating procedure documents namely COOP-3-TSLO-005, *Unit 3 Turbine Lube Oil*.[63]

This delay in updated information is particularly concerning because the Company represents that operators receive little or no formal in-classroom training, but instead "operators use plant drawings, P&IDs, vendor manuals, and on the job experience during their training to learn the system.[64]

e. Poor Maintenance Practices Contribute to Lower Plant Reliability

It was noted that the Human performance team did not mention any maintenance in their report, but the investigation uncovered two specific occurrences relating to poor or inadequate maintenance that are could ultimately result in reduced reliability of the power plant:

- The Company acknowledged that the 6-way transfer valve was never dismantled and inspected since the plant went commercial in 2010. Maintenance and reliability go hand in hand. Without a consistent maintenance program, reliability will in the long run suffer. The Company should include periodic dismantling and inspection of the 6-way transfer valves as an element of the plant's regularly schedule O&M activities.

- After the Lube Oil 6-way valve incident [i]t was discovered that the lube oil filter elements had not been changed for several years. The manufacturer recommends that the filter elements be changed when the differential

[60] Confidential Response CPUC13-4.A2.
[61] Ibid.
[62] Confidential Response CPUC13-6.A.1.
[63] Confidential Response CPUC13-1.
[64] Confidential Response CPUC13-2.

pressure, across the filter element, reaches 15 psi or every six months of operation. Another finding of significance was made during the lube oil flush. Small wires and magnetic particles were found in the filter bags at the turbine bearing jumper oil lines. The source of the wires was found to be a failed filter element.[65]

It is unknown whether the two maintenance incidents on the TLO system described above are isolated maintenance lapses or whether they are indicative of a lack of adequate maintenance practices in the plant as a whole. This is a concern. It is recommended that the Human Performance Team review general maintenance practices for gaps for critical plant systems, and update O&M manuals and training as appropriate in order to improve operations and maintenance practices.[66]

f. Inconsistent Training Practices and Incomplete Documentation of Mastery of Knowledge

The Company provided extensive documentation on its operator training programs. Development of the training programs is a cooperative effort between the Union (i.e. International Brotherhood of Electrical Workers Local 111) and the Company. The Company represents that operator training is done using three training techniques that include: completion of a sixty-three page "On-The-Job" guide under the supervisions of a Senior Operator and reviewed by a Functional Joint Apprenticeship Committee (FJAC); "in-classroom" time which comes in the form of time spent studying available material like drawings, P&IDs, and vendor manuals; and adequate scoring on a standardized test concerning material in the PSA on-the-job training (OJT) guide.[67]

Specific information that documented that the PSA1 involved in the June 2020 incident had received adequate and through training in the operation and maintenance of the Comanche #3 turbine was requested in the course of this investigation. The Company represented that the PSA1 completed his OJT guide on April 29, 2018, but the Company could not produce a completed, signed and reviewed document copy of the training activities demonstrating completion of the required training. The Company instead provided a blank copy of the OJT guide as a sample[68] which listed as General References; many of which the Human Performance Team identified as incomplete or in need of updating.

For the turbine lube oil system, the OJT guide states the operator must demonstrate knowledge of:

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[65] Confidential Attachment CPUC2-2b.A4, p. 281.
[66] ASME RAM-1-2013 Reliability, Availability, and Maintainability of Equipment and Systems in Power Plants.
[67] Confidential Response CPUC13-2.
[68] Confidential Attachment CPUC13-2.A2, p. 57.

- Purpose of the system;
- Know location and purpose of Lube Oil Vapor Extractor;
- The location of the Main Oil Pumps;
- Know location and purpose of following pumps:
  - Emergency Bearing Oil,
  - Turning Gear Lube Oil, and
  - Jacking Oil Pump and Source of Supply to pumps;
- Location and purpose of Lube Oil Coolers and describe method of cooling;
- Location and purpose of Turbine Lube Oil Filter and how to swap filters while the plant is online; and
- Know why the TLO system needs to be in service before hydrogen is put in generator.

The Company did produce a copy of the specific PSA1's final OJT test, but it was noted that the test is extremely general and standardized. It is concerning that the Company was unable to document the PSA1 operator's mastery of the OJT guide on his assigned equipment.

g. Some Issues Not Addressed by CMI Team

The Configuration Management Improvement Team did not revise Procedure COOP-3-TSLO-005, Unit 3 Turbine Lube Oil, but the Human Performance Team did recommend that certain procedures relating specifically to this incident require revision reporting:

> Procedure COOP-3-TSLO-005, Unit 3 Turbine Lube Oil, did not provide a clear desired alignment for TLO cooling. Gaps in the procedure to ensure the system was in the appropriate configuration were reliant on individual knowledge."[69]
>
> "Procedure for lube oil start up does not contain adequate direction to ensure valve lineup or the desired configuration for startup – no direction in procedure for desired valve lineup prior to start-up of turbine. Comanche 3 Startup procedure, COOP-3-CSUC-001, states to use procedure COOP-3-TSLO-005, Comanche 3 Turbine Lube Oil, to put the lube oil system in service. COOP-3-TSLO-005 does not provide clear guidance on the desired valve lineup for oil and cooling water for startup. The Sr. Operations Manager remarked that the procedure was not adequate in interviews but was surprised by the deficiencies.[70]

It is recommended that the Company develop and implement a specific procedure to operate the transfer valve or modify the existing procedure. Due to the complexity and importance of the TLO six-way transfer valve, a specific procedure or an addition

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[69] Confidential Attachment CPUC1-2.A1, p. 7.
[70] Ibid., p. 8.

to the existing procedure, with sign off, should be completed to assure correct operation of transfer valve. Procedures should emphasize communication between control room and local operators.

h. General Observations

Staff's investigation into 2020 outage causes and corrective actions focused on trying to understand the big picture. Specifically, why is Comanche 3, a unit still in the first decade of its 60-year useful service life, plagued with such poor unit reliability? In general, poor unit reliability is usually the result of a combination of poor equipment design and substandard O&M practices. This investigation revealed that this is likely the case for the Comanche 3 2020 outages.

The Company has a responsibility to prudently manage Comanche 3 using industry best practices. However, the reviews performed by the Company and outside experts appear to suggest otherwise. While the Company's actions in response to the event are commendable, especially the engaging of outside consultants to assist in determining the cause and corrective actions to mitigate future incidences, it is not clear that these actions provide adequate assurance that a similar incident will not occur in the future.

[redacted]

> [redacted][71]

[redacted]

> [redacted].[72]

[redacted] are even more concerning when considered with a statement made by Xcel Energy's Chairman and Chief Executive Officer Ben Fowke on the Company's 2020 4th quarter earning call where he appeared to connect strong financial performance with reduced O&M spending:

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[71] Confidential Attachment CPUC2-2b.A4, p. 8.
[72] Confidential Attachment CPUC2-2b.A2, pp.3, 10-12.

> In addition to strong performance, we have continued to lower our cost structure with O&M costs declining by more than 5% in 2020.[73]

The issues [redacted], as well as the root cause analysis for the TLO incident, suggest that reduced attention to O&M activities likely contributed to the recent Comanche 3 extended outages. Unfortunately, there was no evidence that the Company is planning to increase O&M investments as an element of its corrective action.

F. Comanche 3 Chemistry

Comanche 3 is a supercritical, pulverized coal plant that is designed with state-of-the-art technology (at the time) that requires the boiler be operated at high pressures and temperatures when compared to traditional coal plants.

Staff's review of third party reports and studies order by PSCo, specifically regarding the low pressure steam turbine blade failure in January 2020, found that the while not readily apparent and not impacting day-to-day operations, Comanche 3's cycle chemistry during the first ten years of operation has not met the standards expected for a supercritical unit.

Proper steam cycle chemistry is a key requirement for performance that minimizes equipment damage and efficiency losses and maximizes plant reliability. Improper or poorly managed cycle chemistry will almost guarantee corrosion deposits, scale, and carryover that will contribute to pit-induced stress corrosion cracking (SCC) experienced at Comanche 3 steam turbine.

i. Importance of Cycle Chemistry

Safe, reliable operation of large steam power generating plants such as Comanche 3 depends upon the establishment of chemical conditions throughout the steam-water circuit that minimize the corrosion of system components and suppress the formation of deposits that contribute to corrosion propagation. This comprehensive view is also referred to as cycle chemistry.

The chosen chemical treatments and instrumentation will depend upon the details of plant type, circuit design, metallurgy, physical parameters (temperatures, pressures, heat fluxes, etc.) and intended operational mode of the plant (base, medium or peak load operation, frequency of starts, and ramping changes and shutdown operation). Proper steam cycle chemistry is a key requirement for performance that minimizes equipment damage, loss of efficiency, and in maximizing plant reliability.

Cycle chemistry means different measures and treatments utilized for specific equipment and during different stages of unit operation, startup, operational and

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[73] See https://www.fool.com/earnings/call-transcripts/2021/01/28/xcel-energy-inc-xel-q4-2020-earnings- call-transcript which is the written transcript for the XEL earnings call for the period ending 31, 2020. Recorded on Jan 28, 2021 at 10:00 a.m. Eastern Time.

shutdown and prolong periods of shut down extending greater than 3 days. Some chemical treatment or recommended protections are simply the use of dehumidified air in steam turbine enclosures during periods of shut down extending beyond three days.

ii. Major Chemistry Events Impacting Comanche 3 Operations

Section V of this report identifies and provides brief discussion on major equipment outages or failure during the first 10-years of Comanche 3 operations. When equipment fails, root cause analysis is required to identify what occurred and what the contributing causes were over the short and long term.

As a result of Comanche 3 low pressure steam turbine failure, PSCo retained the services of outside consultants and service providers in early 2020 to assess the conditions leading up to the failure of the steam turbine. These reports and assessments provided by several third parties provide valuable and detail assessments of the mode of failure and contributing causes. The SI report on cycle chemistry provided a detailed assessment of the maintenance of the Comanche 3 cycle chemistry by SI.[74] .

SI notes that the original Comanche 3 cycle chemistry instrumentation was designed with the accepted standards for supercritical units at the time (2000 era), but the actual performance since commercial operations in 2010 was far removed from acceptable standards or considered poorly managed. The Steam Purity Recommendation or Comanche Guidelines PSCo uses to operate Comanche 3 were considered outdated by 20 years in 2020. [75]

This would include poor calibration, maintenance, and reliability of instruments. The instruments have not provided the required accuracy for the operations to realize serious contamination alarms limits, and shutdown conditions are ignored.[76]

For example, a condenser leak was ignored in March 2012, and Comanche 3 remained operating for days, resulting in serious contamination of plant internal surfaces, while sodium concentration, Conductivity After Cation Exchange (CACE), and conductivity upper limits where ignored and followed by no cleaning of contaminated surfaces.[77]

Comanche 3 operations during the first 10-years allowed Operators to ignore alarms and shut down situations, not using optimum chemistry treatment, ineffective monitoring of total iron as the key indicator of chemistry and unreliable chemistry instrumentation. [78]

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[74] Confidential Attachment CPUC2-2b.A2.
[75] Ibid., p.28.
[76] Ibid., p. 41.
[77] Ibid., pp. 3-4.
[78] Ibid., pp. 3-4.

Further, there has been lack of any chemistry controls to provide steam turbine protection during shutdown. The SIA report identified numerous inadequate or unprotected shutdown events extending 446 days between 2012 and 2019 that could contribute to steam turbine damage through outside moist air leakage into turbine during outages exceeding three days. Moist air leakage into the turbine, or hygroscopic adsorption into turbine, can lead to pitting, a precursor to corrosion. [79]

Air leakage is an issue at Comanche 3 without any guidance manuals or procedures in place to control oxygen levels.[80] Uncontrolled air leakage contributes to higher than expected oxygen levels for a supercritical unit, contributing to an internal environment conducive for corrosive conditions.

iii. Finishing Superheater Replacement

Staff was made aware of a finishing superheater replacement at Comanche 3 at a cost of $11,641,342 during Proceeding 19AL-0268E, the 2019 PSCo electric rate case. Intervenors in that proceeding propounded numerous discoveries to better understand why the finishing superheater was replaced after a relatively short in-service life of only five years. PSCo provided extensive responses and explained their conclusion that the failure of the original finishing superheater was due to its use of T91, a high in chromium alloy, that turned out to be unsuitable for this application.

The original equipment manufacturer shared with PSCo their concern that the internal tube exfoliation and scale observed, which was friable and easily transported, was not the cause of blockage or hot spots. The equipment manufacturer attributed blockage, hot spots and tube leaks to the condensate water; water that PSCo controls.

PSCo retained the services of SI to provide review of the Mechanism and Root Cause of L-1Blade Failure and Assessment of Cycle Chemistry. While helpful, this report provided no discussion on the failure of the original finishing superheater or whether cycle chemistry contributed to the failure of the equipment. Regardless, it quite possible that improper cycle chemistry was a contributing factor toward early failure of finishing superheater and not the wrong alloy used.

iv. Staff Recommendations on Cycle Chemistry

The recommended management actions for Comanche 3 operation provided [redacted] are appropriate and include:

i. Development of shutdown/layup procedures and techniques to provide chemistry protection to the boiler, reheater, feedwater heater and steam turbine;
ii. Move the Chemistry at Comanche to full Oxygenated Treatment;

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[79] Ibid., pp. 16-17.
[80] Ibid., p. 27.

iii. The operating chemistry limits should be in alignment with the latest international guidance for supercritical units as reference in [redacted]
iv. Incorporate all the chemistry activities into the development of a Comanche Chemistry Manual as reference on [redacted];
v. Upgrade operational practices linked to upgraded cycle chemistry controls. These include the use of auxiliary steam, by-passing the condensate polishers, and attemperation/regulating;
vi. Develop procedures and protocol to measure total iron around the cycle using IAPWS Technical Guidance Documents as baseline;
vii. Upgrade the whole cycle chemistry instrumentation system to be a major resource for Comanche 3 operations. This will involve purchasing some new unique instruments (not share/sequenced), more frequent calibration/maintenance, and ensuring the instruments work during startups;
viii. Training of operators in the upgraded chemistry procedure in relation to failure mechanisms that can occur in supercritical plant;
ix. Consider an early boiler waterwall chemical clean to avoid future boiler tube failures;
x. Investigate/inspect the internal surfaces of reheater to check for signs of pitting; and
xi. Consider an inspection of the repaired LP steam turbine after about one year with a concentration on the areas around the snubber.

IV. Costs of June 2, 2020 Incident

A. Estimated Cost for Repair of Damages Incurred

As described above, the June 2, 2020 incident caused significant damage to the steam turbine and related systems and resulted in the unit being out of service through the end of 2020. As a result of the damage, Public Service incurred significant capital and O&M expenses to bring Comanche 3 back online. Table 1 below shows the main projects necessitated by the June 2 event, the capital costs for each project, and the total O&M associated with the repairs.

Table 1. Comanche 3 repair costs due to June 2, 2020 incident.[81]

Repairs and replacements required	PSCo Costs ($millions)		
	Capital	O&M	Total
Replace Generator Rotor Fan Blades	$0.3		
Generator Rotor Rewind and Hydrogen Blower	$4.4		
Low Pressure A and Low Pressure B Turbine Blades Replacement	$3.1		
Replace Steam Turbine Train Seals	$1.8		
Totals	$9.8	$10.6	$20.4

The Company has indicated that it believes insurance will cover all of these O&M costs and almost all of these capital costs. If the insurance adjustor agrees with the Company's claim, PSCo's responsibility would be its share of the $2 million policy deductible ($1.3 million) plus overheads, which would total about $1.5 million.[82]

B. Estimated Cost of Replacement Power Incurred

The June 2 incident resulted in a prolonged outage for Unit 3 lasting through the end of December 2020. During this time, PSCo had to procure more expensive replacement power to serve customers than would otherwise have been necessary if Unit 3 was operational. Without Unit 3 operating, PSCo produced energy from more expensive owned plants and also made market purchases to source power from other suppliers. These replacement power costs, in addition to the capital costs for the damaged unit, are directly attributable to the June 2 incident. One approach to estimating replacement power costs is to use a computer model to simulate what

[81] Confidential Attachment CPUC14-2.A1. Total station costs were multiplied by 0.66 to determine PSCo's share.

[82] Costs assuming insurance coverage provided in Confidential Attachment CPUC11-1.A1. Confidential Response CPUC10-4 explains the calculation and allocation of deductible and overhead costs.

system dispatch would have been if Comanche 3 had been operating and compare this with the actual system costs incurred during the outage period.

At Staff's request, PSCo estimated replacement power costs from the June 2 incident using a computer model called GenTrader. This model was calibrated to reflect the actual system conditions, costs, and transactions that occurred during 2020 without Comanche 3. The model was then re-run to simulate system operations with Comanche 3 operating and the cost difference was calculated. Using this method, total net replacement power costs due to the Comanche 3 outage from June through December, 2020 were estimated to be $14,392,578. Approximately $9.5 million of these costs occurred in August, followed by $5.1 million in July. Table 2 displays the replacement power costs by month.[83]

Table 2. Comanche Unit 3 outage replacement costs, June–December 2020.

Total	**$ 14,392,578**
Total w/o negative months	**$ 15,495,953**
June	$ 398,141
July	$ 5,087,291
August	$ 9,465,161
September	$ (44,888)
October	$ 545,360
November	$ (264,618)
December	$ (793,869)

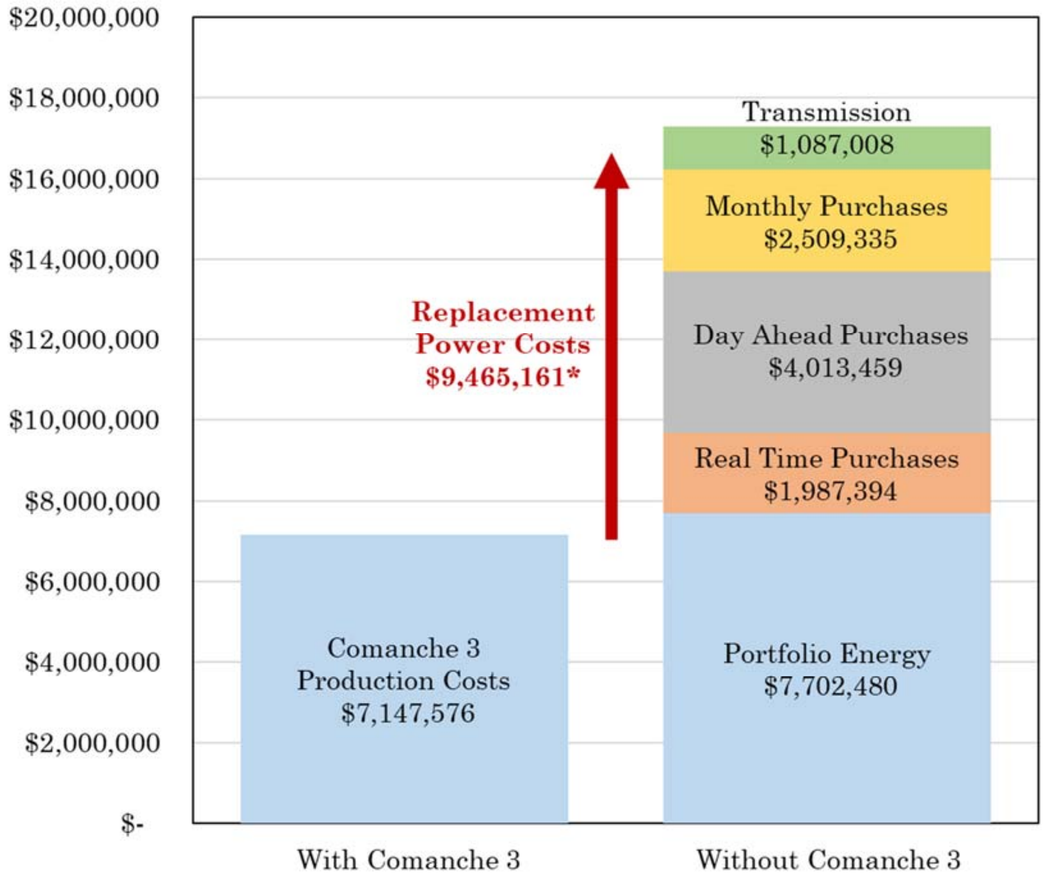
Interestingly, the model estimated net negative replacement costs during September, November and December. During these months, it was cheaper to supply PSCo's customers with Unit 3 offline. Total replacement costs are $15,495,953 if we exclude these "negative cost" months. These negative results for the non-summer months raise the question of whether seasonal operation of Comanche 3 in future years, as well as other coal plants owned by PSCo with incremental costs above Comanche 3, might be in the public interest. The results suggest that, had Comanche been operating during these months, PSCo consumers would have paid more for energy. As such, there may be a system benefit from taking Comanche 3 offline for economic reasons from September through December (and potentially other seasons as well).

These replacement costs come from a variety of resources. First, when Comanche 3 is offline, PSCo has to increase production from its remaining generating units. For purposes of this investigation these will be called "portfolio energy costs". When PSCo's system resources are fully utilized, and/or when lower cost energy is available from the bilateral market, PSCo will engage in market purchases that can occur in real-time, day-ahead, and month-ahead timeframes. These market transactions incur

[83] Confidential Attachment CPUC2-13g.A3.

costs and PSCo must also pay for transmission to deliver this external energy to serve its load.

Each of these components contribute to the costs that would not otherwise have been incurred if Comanche 3 was operating. To illustrate, Figure 17 provides a breakdown of the cost components for the month of August 2020 as an example. The left bar reflects the estimated cost had Comanche 3 been operational and the right bar provides an estimate of the cost of the replacement resources. During this month, PSCo incurred \$7.7 million in portfolio energy costs, \$2 million in real-time purchases, \$4 million in day-ahead purchases, \$2.5 million in monthly purchases, and \$1.1 million in transmission purchases, totaling \$17.7 million in costs necessary to replace Comanche 3's power. If Comanche 3 were online, it would have produced the energy needed to offset these costs, but the unit would have incurred its own set of production costs. These were estimated to total \$7.1 million. The incremental costs incurred by ratepayers is the difference between these two. After a few minor modeling adjustments to reflect outage probabilities and wind uncertainty, incremental power replacement costs due to Comanche 3 outage for the month of August come to \$9,465,161. This is the same method used to determine the incremental replacement costs for each month from June through December 2020, the results of which were previously shown in Table 2.



*Reported replacement costs do not exactly equal the difference in the two bars, due to a $686,939 downward model adjustment to reflect Comanche's forced outage probability and wind production uncertainty.

Figure 18. Replacement power cost estimates for Comanche 3 outage, August 2020.

C. Short Term Purchases Related to the June 2, 2020 Incident

The previous discussion illustrates our best estimate of replacement power costs incurred due to the 2020 Comanche outage. A large component of these costs are from external market purchases PSCo made to serve its load in the absence of Comanche 3. Staff investigated PSCo's summer transactions data in more detail in the context of this extended Comanche 3 outage.

PSCo purchased $25 million worth of external energy through short term transactions in 2020, compared to $9.9 million in 2019, and $4.9 million in 2018. Most of these purchases occurred in July and August, as shown in Figure 18. This is consistent with the previously described Comanche 3 replacement power estimates also being largest in July and August. This data shows that the Comanche 3 outage significantly exacerbated system costs during the summer, causing PSCo to purchase relatively large amounts of expensive energy on the spot market.

The cost of short-term purchases for Comanche 3 replacement power estimated with the GenTrader simulation model in the previous section is a subset of PSCo's total short-term purchases. For example, in August the GenTrader model estimated $8.5 million of short-term replacement energy, out of $11.7 million total short-term purchases made by PSCo. The difference in these accounts is driven by PSCo's need to purchase some external energy during these summer months even if Comanche 3 were online.

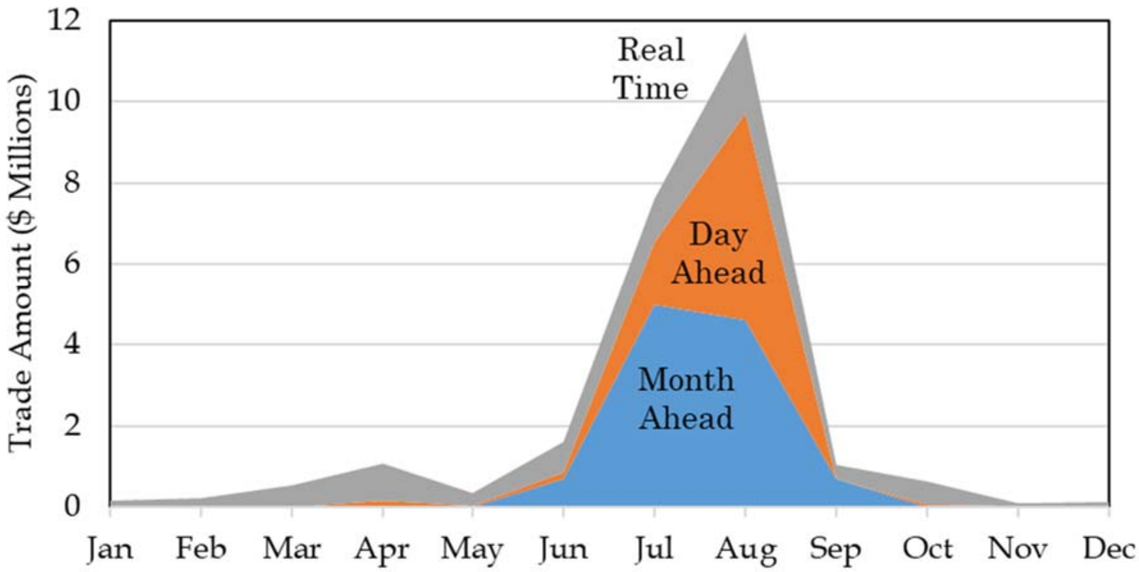


Figure 19. PSCo short term market purchases in 2020 by month. [84]

Table 3 lists the top 10 trading counterparts with whom PSCo engaged in short term market transaction during 2020. The purchasing behavior with each counterpart in follows the same general pattern described above, with most transaction volumes occurring in the summer. PSCo's highest priced transaction was with Black Hills Energy Corporation in which they purchased a single megawatt-hour (MWh) at 7pm on June 30 for a price of $1,680/MWh, even though they were the 12th largest trading partner with a 2020 transactions totaling $651,325. The next highest-priced transaction involved 135 MWh purchased during the afternoon of August 19 from Transalta Energy Marketing at a price of $950/MWh. The top five days in 2020 with the largest purchase volumes all occurred in late August, maxing out at over a million dollars per day, as shown in Table 4.

Table 3. Top 10 trading counterparts with PSCo, 2020.

Counterpart	Amount ($)
Colorado Springs Utilities	5,038,385
Basin Electric Power Cooperative	4,588,861
Tri-State G&T	2,659,597

[84] Confidential Attachment CPUC9-2.A1 and 9-3.A1.

Morgan Stanley Capital Group	2,542,422
Platte River Power Authority	1,922,681
Southwest Power Pool	1,775,624
PacifiCorp	1,703,814
Rainbow Energy Marketing Corporation	904,486
Macquarie Energy LLC	880,060
Brookfield Renewable Trading and Marketing LP	735,668

Table 4. PSCo's highest volume days for short term energy transactions, 2020.

Day	Purchase Volume ($)	Average Price ($/MWh)
8-24	1,024,721	70.79
8-21	1,000,123	59.96
8-22	814,221	58.56
8-25	757,087	44.50
8-20	682,828	37.33

Staff also collected historic short-term market purchases data to put 2020 in a broader context. PSCo's short-term transaction volumes by year are displayed in Figure 19 below. This shows 2020's market purchases increased over several of the previous years, continuing a growing trend beginning in 2016. However, PSCo reported larger volumes of day-ahead/real-time ("DA/RT") purchases in earlier years, such that purchases in 2010 were significantly higher than what was experienced in 2020. Staff was not able to investigate the full reason behind these high 2010 to 2013 volumes, in part because PSCo's legacy accounting system prevented them from providing more detailed data on the historic transactions.

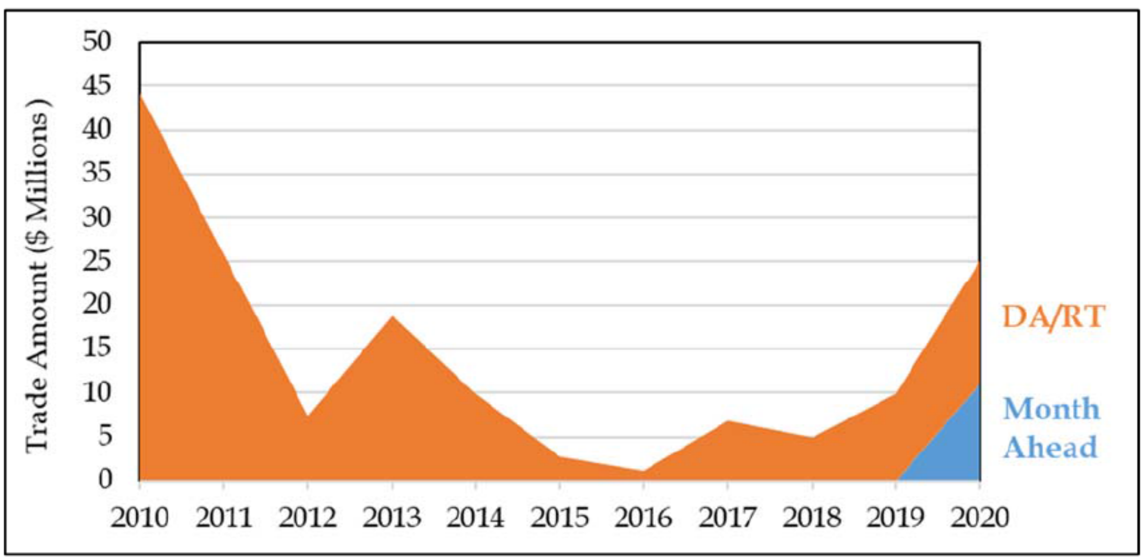


Figure 20. PSCo short term transaction volumes by year.

D. 2020 Coal Supply

Public Service arranges for the purchase of coal and coal transportation for all three Comanche units via Master Coal Supply Agreements ("MCSA"). As of today, the Company is unaware of any coal supply or transportation contractual penalties paid during the period of 2009 through 2020. The Company states that "[i]n some years, including 2020, Public Service was not able to receive all of the coal that it had purchased for the applicable period. In some cases, Public Service was able to carry forward a portion of the coal quantity to another period (e.g., the following year) and in other cases Public Service relied upon the force majeure provisions of its coal supply agreements to reduce the contractual commitments. In no case did Public Service pay any damages (e.g., take-or-pay) under its coal supply or coal transportation agreements during the period of 2009 through 2020."[85] The force majeure clauses included in the MCSA generally include equipment failure as a valid reason for Public Service to provide written notice and suspend any obligation to perform.

In addition to the Company's explanation of coal supply contractual arrangements, the actual Comanche coal expenses charged to the Energy Cost Adjustment ("ECA") indicate minimal Comanche 3 fuel costs for 2020. The Company projects that the fuel and transportation costs for fuel supply at Comanche 3 in 2020 is 4 percent of the average fuel costs for the 2010 to 2019 period. This is consistent with the approximately 3 percent capacity factor of the unit in 2020.[86] The contractual arrangements and actual ECA fuel costs provide reasonable assurance that customers are not charged for fuel or transportation in the event of a plant shut-down or interruption of service, such as occurred in 2020.

This discussion regarding the fuel costs for Comanche unit 3 included all fuel and transportation costs but excluded fuel handling costs. Fuel handling costs are generally treated as O&M expenses and are not recovered through the ECA. Rather fuel handling costs are included in base rates. Fuel handling expenses for the three Comanche units for calendar year 2018is $4.2 million.[87] These costs are consistent with the relatively normal operating conditions at the facility throughout 2018.

E. Conclusions

In summary, repair activities from the June 2 incident involved $20.4 million in capital and O&M costs in 2020. PSCo expects these costs to be covered from its all-risk property insurance policy machinery breakdown clause.[88] If this turns out to be true, the Company would owe its $1.5 million portion of the deductible. PSCo expects

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[85] Confidential Response CPUC6-7.

[86] Staff also notes that the fuel expenses in 2020 for Comanche units 1 and 2 are roughly consistent with the average fuel costs for the 2010 to 2019 period.

[87] Confidential Attachment CPUC6-3.A2.

[88] Confidential Response CPUC14-3.

the initial insurance adjuster report to be completed in 2021, although specific timing is uncertain.[89]

The other significant component of costs from the June-December 2020 outage is from PSCo's need to procure more expensive power in the absence of Comanche 3. These replacement power costs totaled a net $14.4 million, according to PSCo's simulations. PSCo engaged in short term purchases during 2020 summer months at particularly high prices, driving replacement power costs higher. During September and December of 2020, having Comanche 3 offline actually saved customers money, suggesting that cycling Comanche 3 for month- or season-specific operation is worth further investigation.

[89] Communicated to PUC Staff during call with PSCo on February 16, 2021.

V. Performance History

A. Outage Histories and Costs

The following figure is a timeline that summarizes the major outages (defined as occurring for three days or more) that occurred for Comanche Unit 3 since its Commercial Operation Date ("COD") of July 6, 2010. The number of days the unit was unavailable is shown in parentheses for each outage listed. The planned outages are indicated in blue to differentiate them from the unplanned/non-routine outages.

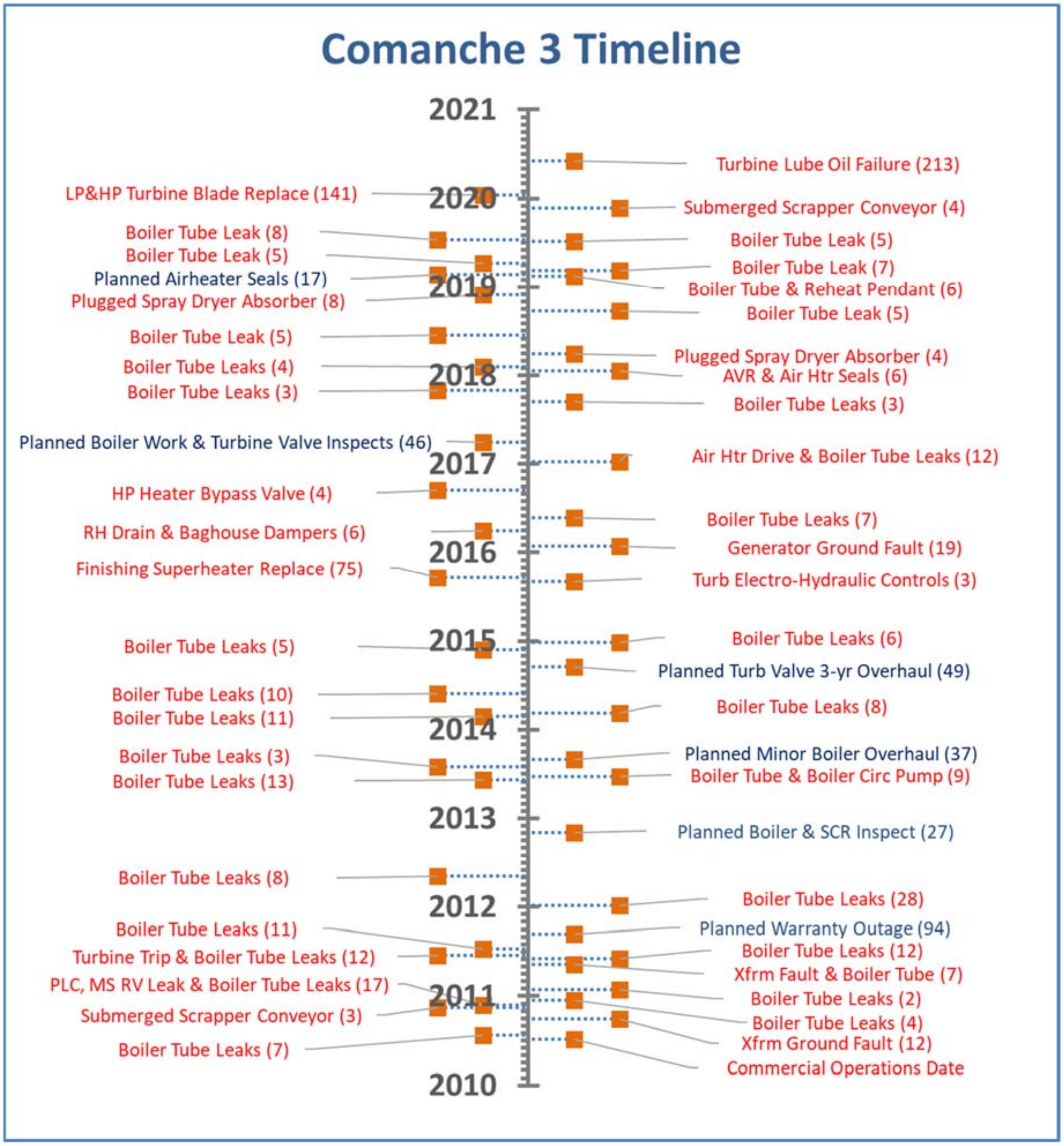

Figure 21. Comanche 3 outages timeline.

Figure 21 summarizes the costs associated with each outage, including O&M and capital costs from the activities completed during the outage. It also includes replacement power costs. These were estimated using a software model called CostCalculator, which was parameterized using historic Comanche 3 marginal costs, system costs, and external purchases prices to estimate the incremental cost to ratepayers of having Comanche 3 offline during each outage. Prior to the events in 2020, there were extended planned outages for warranty work in 2011, a valve overhaul and catalyst replacement in 2014, and the superheater replacement in 2015. There were many boiler tube leak forced outages during these earlier years each of which was relatively short, but which tended to occur during more expensive periods. These boiler tube leak outages decreased noticeably for a couple years after the 2015 superheater replacement. The average replacement power costs for the tube leak outages was $137,762 per day, compared to $73,330 per day for all other outages.

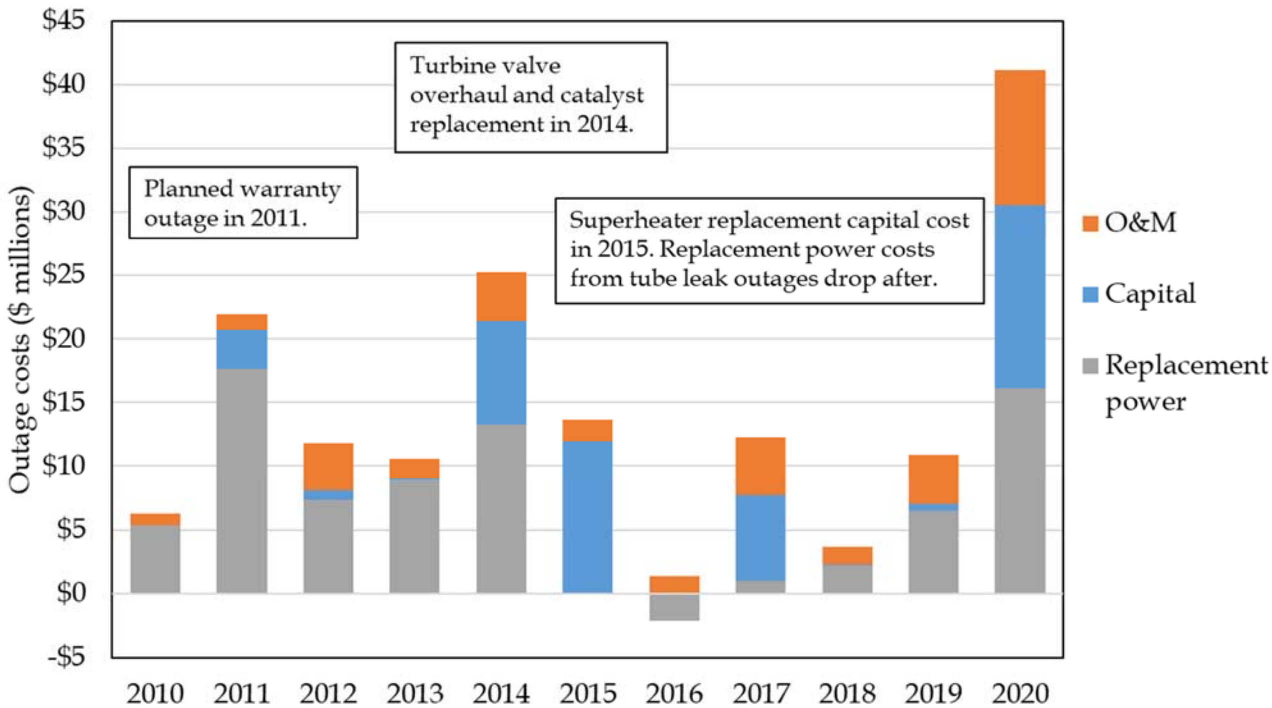

Figure 22. Comanche 3 outage costs by year.

Below is a summary in reverse chronological order of the outages that occurred over the period from the COD of July 6, 2010 through the June 2, 2020. The June 2, 2020 outage that occurred at the time that the unit was being returned to commercial service after completion of the January 13, 2020 outage was addressed in detail above.

i. 2019 Outages

November 21, 2019 - Submerged Scrapper Conveyor (4 Days)

This was a relatively short outage due to a chain that broke on the submerged scraper conveyor. It was necessary to empty the coal hopper to enable repair activities. Comanche 3 was in an outage state for 4 days returning to service on November 24, 2019.[90]

February 20, 2019 - Planned Outage to Replace Air Heater Seals (17 Days)

This was a planned outage scheduled to take place during the winter to replace the Comanche 3 air heater seals. Comanche 3 was in an outage state for 17 days returning to service on March 8, 2019.[91] Boiler tube leaks were identified and worked on directly before and after this job, extending the outage further. Outage activity capital and O&M costs were identified at $2.9 million, and replacement power costs were estimated at $2.2 million.

Boiler Tube Leaks – 2019 (31 Days)

There were also five occurrences of boiler tube leaks during 2019 that resulted in 31 days of outage.[92] These outages collectively involved additional Capital and O&M costs of $1.0 million and replacement power costs estimated at $3.9 million.

ii. 2018 Outages

November 30, 2019 – Spray Dryer Absorber Plugged (8 Days)

The Comanche 3 was related to debris in the Spray Dryer Absorber (SDA). SDA systems are designed to capture a variety of pollutants from the flue gas stream including sulfur dioxide (SO2), mercury, acid gases, and particulates. This technology has the added benefits of no liquid discharge and reduced water consumption. The SDA sprays atomized lime slurry into the flue gas resulting in the absorption of acid gases that are then evaporated into a solid particulate. The flue gas and solid particulate then proceed to fabric filters where the solid materials are collected. A diagram of a typical SDA is provided in the figure below.[93]

[90] Confidential Attachment CPUC2-3a.A1.
[91] Ibid.
[92] Ibid.
[93] *Source: Amec Foster Wheeler*

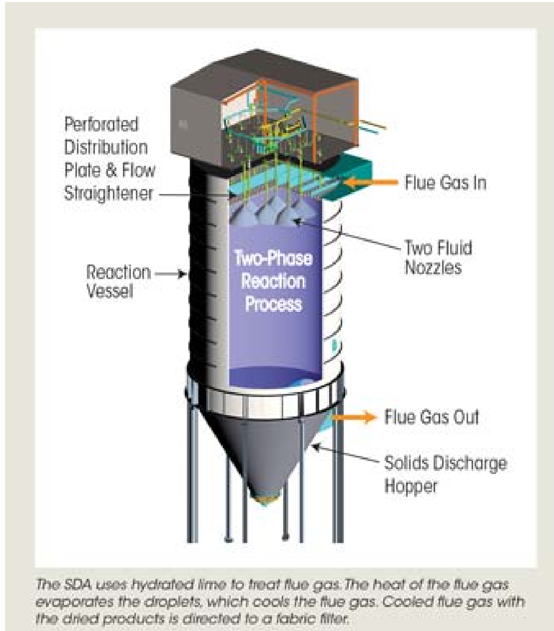

Figure 23. Typical SDA diagram.

This outage was caused by debris which plugged the gas dispersion. The debris was cleared from the gas disperser and bottom of the vessel during the outage.[94] Comanche 3 was in an outage state for 8 days returning to service on December 7, 2018. Replacement power costs for this outage were estimated at $1.4M.

March 29, 2018 - Spray Dryer Absorber Plugged (4 Days)

A similar, but shorter, SDA plugging event occurred early in the year where Comanche 3 was in an outage state for 4 days returning to service on April 1, 2018.[95]

January 20, 2018 – Repair Automatic Voltage Regulation (6 Days)

The purpose of this outage was to repair the automatic voltage regulator (AVR) system so that automatic generation control (AGC) could be restored. The AGC and AVR system work together to provide delivery of power from the fleet of generating units in an economic reliable manner while maintaining the voltage and frequency within permissible limits. The Company also completed the replacement of air heater seals since the unit was down a sufficient amount to time to complete this task. Comanche 3 was in an outage state for 6 days returning to service on January 25, 2018.[96]

[94] Confidential Attachment CPUC2-4a.A1.
[95] Ibid.
[96] Ibid.

Boiler Tube Leaks – 2018 (14 Days)

There were also three occurrences of boiler tube leaks during 2018 that resulted in 14 days of outage.[97]

iii. 2017 Outages

April 1, 2017 – Planned Boiler Work & Turbine Valve Inspections (46 Days)

This was a planned outage to complete major (more than 720 hours) maintenance activities for the boiler and to complete turbine valve inspections. In addition, this planned outage included the scheduled replacement of the bottom layer of catalyst in the Selective Catalytic Reduction (SCR) system.[98] The SCR system removes nitrogen oxides (NOx) from flue gas. Comanche 3 was in an outage state for 46 days returning to service on May 16, 2017. Staff identified \$6.7M in capital costs and \$3.9 in O&M expenses from activities during this extended outage. Replacement costs from this outage were only estimated to be \$4,079, as it occurred during a period of low system costs that were not incrementally higher than Comanche 3's production costs.

January 10, 2017 – Air Heater Drive Gearbox Failure (12 days)

The purpose of this outage was to repair a gearbox failure for the A-train air preheater. The air preheater system recovers waste heat from the flue gas leaving the boiler for the purpose of preheating the combustion air entering the boiler. The system has the added benefit of reducing the flue gas entering the emission control systems increasing their effectiveness. Several boiler leaks were also discovered and repaired during the outage. Comanche 3 was in an outage state for 12 days returning to service on January 21, 2018.[99]

Boiler Tube Leaks – 2017 (6 Days)

There were also two occurrences of boiler tube leaks during 2017 that resulted in 6 days of outage.[100]

iv. 2016 Outages

September 12, 2016 – High Pressure Heater Bypass Valve (4 Days)

The outage was related to a repair that was required on the B train high pressure feedwater heater bypass valve which was described as limiting generation capacity. The Company provided only limited information on this outage, but because it resulted in no capital expense and only 4 days of outage, no further inquiry was

[97] Ibid.
[98] Confidential Attachment CPUC2-5a.A1.
[99] Ibid.
[100] Ibid.

made.[101] The SCR system removes nitrogen oxides (NOx) from flue gas. Comanche 3 was in an outage state for 4 days returning to service on September 15, 2016.

March 29, 2016 – Repair and Replace Reheat Drain and Repair Baghouse Dampers (6 Days)

The outage was required to repair and replace a leaking Hot Reheat drain line and well as to inspect and repair baghouse inlet dampers. The repair and replacement activities resulted in no capital. Comanche 3 was in an outage state for 6 days returning to service on April 3, 2016.[102]

January 27, 2016 – Generator Ground Fault (19 Days)

The outage is described as being caused by a ground fault of the generator. The repair activities resulted in no capital expense, but Comanche 3 was in an outage state for 19 days returning to service on February 14, 2016.[103]

Boiler Tube Leaks – 2016 (7 Days)

There was also one occurrence of a boiler tube leaks during 2016 that resulted in 7 days of outage.[104]

Outage Replacement Power Costs – 2016

All these 2016 outages occurred during periods of low estimated system costs, and the modeled replacement power costs were negative for each individual outage. In total, replacement power costs during these outages in 2016 totaled (-)$2.1M.

v. 2015 Outages

September 18, 2015 – Finishing Superheater Replacement (75 Days)

The outage was taken primarily to replace the finishing superheater that was at issue in Public Service's last rate case where the Commission initially disallowed recovery and then in addressing applications for Rehearing, Reargument, or Reconsideration granted recovery. It was in this same Commission decision that the Commission ordered this investigation.[105] In addition, a number of boiler tube leaks were repaired and the Main Steam drain lines and valves were replaced during this extended outage. Comanche 3 was in an outage state for 75 days returning to service on December 1, 2015.[106] The superheater replacement activities involved $11.9M in capital costs, and another $1.7M in O&M activities. Replacement power costs were

[101] Confidential Attachment CPUC2-6a.A1.
[102] Ibid.
[103] Ibid.
[104] Ibid.
[105] Decision No. C20-0505, Proceeding No. 19AL-0268E, p. 17-23.
[106] Confidential Attachment CPUC2-7a.A1.

actually estimated to be (-)$66,116 during this extended outage, suggesting customers saved a small amount of energy costs with Comanche 3 offline during this extended outage.

September 3, 2015 – Repair Turbine Electro-Hydraulic Controls (3 Days)

The outage was taken to repair the turbine electro-hydraulic controls that were causing problems during startup activities. The repairs were completed without any capital costs. Comanche 3 was in an outage state for 4 days returning to service on September 5, 2015.[107]

vi. 2014 Outages

September 1, 2014 – Planned Turbine Valve Overhaul and Catalyst Replacement (49 Days)

This was a planned outage for the 3-year overhaul of the turbine valve. The Company indicated that there was no capital cost associated with the overhaul. The outage also included the replacement of the catalyst modules in the SCR top level with a capital cost of $5,742,600. Also completed during the outage was a replacement of the existing fly ash material transfer system with a new Alstom dry-drag conveyor system with a capital cost of $1.8M. Last, the Company replaced the fan drive units at a cost of $214,963 and installed a boiler acoustic monitoring system at $350,422. There were $3.4M in additional O&M activities associated with the extended outage. Comanche 3 was in an outage state for 49 days returning to service on November 1, 2014, and replacement power costs during this time were estimated at $3,261,447.[108]

Boiler Tube Leaks – 2014 (40 Days)

There were also five occurrences of boiler tube leaks during 2014 that resulted in 40 days of outage.[109] The collective length of these outages throughout the year imposed substantial replacement power costs, estimated at $9,976,705.

vii. 2013 Outages

August 31 – Planned Minor Boiler Overhaul & ID Fan Inspection (37 Days)

This was a planned outage for scheduled overhaul of the Boiler. In addition, inspections of the Induced Draft Fan and auxiliary systems were completed. Comanche 3 was in an outage state for 37 days returning to service on October 6, 2013.[110] Capital and O&M activities during this outage cost $1,379,293 and replacement power costs during this extended period were estimated at $4,449,493.

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[107] Ibid.
[108] Confidential Attachment CPUC2-8a.A1.
[109] Ibid.
[110] Confidential Attachment CPUC2-9a.A1.

Boiler Tube Leaks – 2013 (25 Days)

There were also three occurrences of boiler tube leaks during 2014 that resulted in 25 days of outage.[111] These outages collectively involved substantial replacement power costs estimated at $4,537,277.

viii. 2012 Outages

November 3 – Planned Boiler and SCR Inspections (27 Days)

This was a planned outage for the inspection of the lower slope corners of the boiler and inspection of the SCR system. In addition to the inspections, the following work was completed during the outage: a control valve was installed in the startup feedwater boiler line; a catalyst testing and analysis system was added to all three catalyst levels in the SCR; the insulation was upgraded on the service water circulating pump; and sonic horns were installed for the third catalyst layer. Comanche 3 was in an outage state for 27 days returning to service on November 29, 2012.[112] This involved $2,959,520 in capital and O&M outage activities, and $4,995,236 in estimated replacement power costs.

Boiler Tube Leaks – 2012 (36 Days)

There were also two occurrences of boiler tube leaks during 2012 that resulted in 36 days of outage.[113] These outages involved $1,457,634 in O&M and capital activities, plus an estimated replacement power cost of $1,939,150.

ix. 2011 Outages

September 10 – Planned Warranty Outage (94 Days)

This was a planned major overhaul required under warranty. The activities included the first-year inspections and overhaul (open, clean, inspect, close) of the high pressure and low pressure turbine trains. Other major tasks completed during the outage included: replacement of the high pressure heater manway and gasket; disassembly, inspections, repairs and reassembly of the boiler feed pump turbine components; inspection and maintenance of the Induced Draft Fan internals; upgrades to the Emerson Ovation Control System; inspection of the Boiler Feed Pump Extraction Check Valve; ultrasonic testing of the finishing superheater tubes for cracking; inspection of the Forced Draft Fans; inspection and cleaning of the Ammonia Injection Catalyst Grids; nondestructive examination of the deaerator and storage tank; renewed the coating and liner on the interior of the demineralized water tank; installed Condensate Booster Pump monitoring system; replaced the positioners for the feedwater and condensate control valves; installed vibration and

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[111] Ibid.
[112] Confidential Attachment CPUC2-10a.A1.
[113] Ibid.

temperature monitoring equipment for the Condensate Booster pumps; installed Ammonia Injection Catalyst grid platforms; installed Continuous Emissions Monitoring System particulate monitor; and repaired the startup boiler feed pump discharge valve. Comanche 3 was in an outage state for 94 days returning to service on , December 12, 2011.[114] Staff documented $3,867,062 in capital and O&M costs associated with this outage, and $9,860,109 in estimated replacement power costs.

June 17 – Turbine Trip & Boiler Tube Leaks (12 Days)

The outage was initiated when a turbine trip occurred due to a drain valve not properly closing on the boiler flash tank. Once the unit was down due to the turbine trip, boiler tube leaks were repaired. Comanche 3 was in an outage state for 12 days returning to service on June 23, 2011.[115]

May 11 – Transformer Fault & Boiler Tube Leaks (7 Days)

The outage was initiated when the unit tripped due by a fault at a temporary transformer. Once the unit was down due to the turbine trip, boiler tube leaks were repaired. Comanche 3 was in an outage state for 7 days returning to service on May 17, 2011.[116]

Boiler Tube Leaks – 2011 (25 Days)

There was also three additional occurrence of boiler tube leaks during 2011 that resulted in 25 days of outage.[117] These outages occurred during particular expensive periods, with replacement power collectively estimated at $7,250,839.

x. 2010 Outages

November 25 – PLC Trip, MS RV Leak & Boiler Tube Leaks (17 Days)

The turbine tripped due to faulty Programmable Logic Control for the Condensate Polisher system. Once the unit was down, several additional tasks were completed during the outage including: repair of boiler tube leaks; and insulating of a pressure gauge on the Main Steam Relief Valve (MS RV) and cleaning and repacking the valve stems to eliminate leakage. Comanche 3 was in an outage state for 17 days returning to service on December 11, 2010.[118] Replacement power costs for this outage were estimated at $1,444,917.

[114] Confidential Attachment CPUC2-11a.A1.
[115] Ibid.
[116] Ibid.
[117] Ibid.
[118] Confidential Attachment CPUC2-12a.A1.

November 13 – Submerged Scrapper Conveyer (3 Days)

A new bushing was fabricated and installed on the submerged scraper conveyer. Comanche 3 was in an outage state for 3 days returning to service on November 15, 2010.[119]

August 11 – Transformer Ground Fault (12 Days)

Comanche 3 tripped as a result of a ground fault at the Unit 2 and Unit 3 startup transformer. Comanche 3 was in an outage state for 12 days returning to service on October 11, 2010. Replacement power costs for this outage were estimated at $1,594,240.

Boiler Tube Leaks – 2010 (11 Days)

There was also two additional occurrence of boiler tube leaks during 2010 that resulted in 11 days of outage.[120] Replacement power costs during these tube leak outages totaled $3,204,319.

The information assembled for the historical outages were first categorized as either planned, other or boiler tube outages, and then tabulated by category. Non-routine or unplanned outages, with the exception of boiler tube outages, were included and tabulated in the "other" category. The boiler tube outages were tabulated separately since the data suggested that this is a predominate cause of outages. A summary of the categorized and tabulated data follows:

Table 5. Number of outages by type, 2010-2020.

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Avg	%
Boiler Tube Outages	28	39	36	25	40	0	7	18	14	31	0	21.6	24%
Other Outages	15	0	0	0	0	78	29	0	18	4	354	45.3	50%
Planned Outages	0	94	27	37	49	0	0	46	0	17	0	24.5	27%
Totals	43	133	63	62	89	78	36	64	32	52	354	91.5	100%

The same data provided above is also presented in graphic form below in Figure 25. What is noteworthy is that planned outages accounted for 26.8 percent of the total outages averaging at 24.5 days per year. The non-routine or unplanned outages, excluding boiler tube outages, accounted for 49.5 percent of the total outages averaging at 45.3 days per year. Last, outages to repair boiler tube leaks accounted for 23.7 percent of the total outages averaging at 24.5 days per year. In total, Comanche 3 has been experiencing outages at an average rate of 91.5 days per year or roughly 25 percent of the time. This is a very troubling metric and should be considered in the modeling or benchmarking of the unit going forward.

119 Ibid.
120 Ibid.

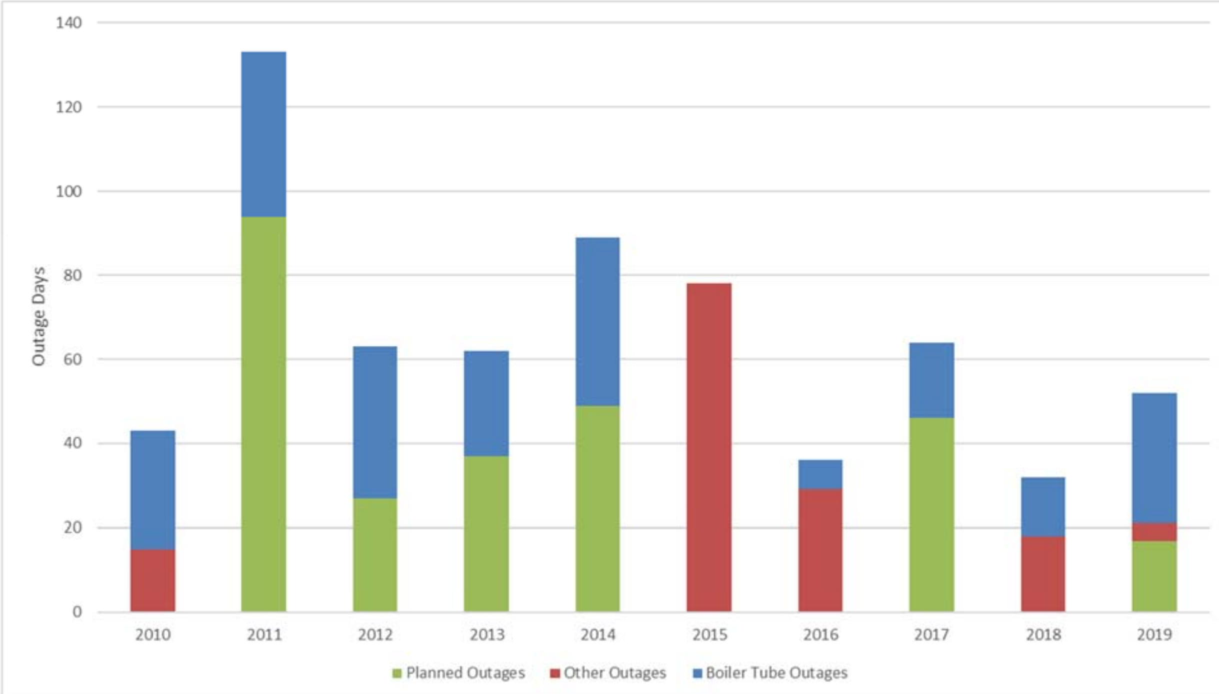


Figure 24. Graphical illustration of Table 5.

B. Availability Factors

Availability is a measurement of the degree to which a generating unit is operable over a certain period of time. It is the proportion of time a system is in a proper functioning condition and capable of producing energy at its maximum output. A unit is considered "available" when it is not experiencing an outage. The more available a unit is, the more it is considered to be reliable in generating electricity. An availability factor ("AF") is a metric that measures the fraction of an operating period in which a unit is available to generate electricity without any outages. It is measured by dividing the amount of time a unit can generate electricity over a certain period by the total amount of time in that period. For example, a generating unit that is capable of operating for 150 hours in a one-week (168 hour) period has an AF of 0.892, or 89.2 percent.

The AF is reflective of only forced outages and scheduled and planned maintenance. When a unit is unable to produce to its maximum capacity due to unscheduled and unplanned outages and equipment malfunction, the unit is referred to as "derated." This derated state is proportionally measured in the electric utility industry using an Equivalent Availability Factor ("EAF"). In other words, the EAF is the fraction of a given operating period in which a generating unit is available without any outages and equipment or seasonal deratings; it is effectively the net availability once all planned and unplanned outages have been considered. Following the above example, if the generating unit is having mechanical problems and can only produce 80 percent of its full load during its operational period, the unit's EAF for the one-week period would be (0.892 x 0.80) 0.714, or 71.4 percent.

Over multiple years, the weighted average EAF can be determined by incorporating the net maximum capacity ("NMC") of a unit. The weighted average EAF is calculated by diving the sum of the products of annual EAF and NMC values by the sum of NMC values.

$$Weighted\ Average\ EAF = \frac{\sum_{i=1}^{N}(EAF)_i(NMC)_i}{\sum_{i=1}^{N}(NMC)_i}$$

Data for both the EAF and AF are available for large generating units in the United States. Both factors are tabulated by the North American Electric Reliability Corporation ("NERC") using data supplied by utilities, and the tabulated EAF and AF values can be accessed via the Generation Availability Data System ("GADS").

When units are not adequately maintained, more complex issues may arise such as operational errors, maintenance manpower shortages, spare part unavailability, logistical delays, lack of opportunity to perform quality repairs, and expensive equipment retrofits. These problems tend to show up as either decreased AF or decreased EAF or both.

Average AF for a power plant varies greatly depending on the type of fuel used, the design of the plant and how the plant is operated. Everything else being equal, plants that are run less frequently have higher availability factors because they require less maintenance. Most thermal power plants, such as coal, geothermal and nuclear power plants, typically have AFs between 70 percent and 90 percent. Newer plants (like Comanche 3, ideally) tend to have higher AFs and EAFs, but may experience low AFs and EAFs during the early stages of their lives due to troubleshooting new technology and operator error. Once this shakedown period is complete, AFs and EAFs should rise as operational risk falls until a stable and predictable operating environment is achieved. During this "mid-life phase," a unit's AF and EAF should remain high and predictable.[121]

Staff's analysis revealed that of all the Company's coal and natural gas thermal generating units, Comanche 3 had the lowest availability during the period from 2010 through October 2020. Comanche 3 achieved an EAF of 70.72 percent in 2010, its first year of operation, reaching a maximum achieved EAF of 91.03 percent in 2018. In 2020, Comanche 3's outages resulted in a significantly low EAF of 4.03 percent. In total, the weighted average EAF of Comanche 3 from 2010 through October 2020 is 71.21 percent. For four of 11 years, or nearly 36 percent of the period of 2010 through October 2020, the EAF of Comanche 3 was below this weighted average value.

Table 6 and Figure 26 below provide availability data for Comanche 3.

[121] Proceeding No. 13I-0215E, Staff Report, 7.

Table 6. NMC and EAF data for Comanche 3 from 2010 through October 2020.

Comanche 3		
Year	**NMC (MW)**	**EAF**
2010	788	70.72
2011	783	57.86
2012	783	77.97
2013	783	82.26
2014	766	71.09
2015	766	75.57
2016	766	87.20
2017	766	80.45
2018	766	91.03
2019	766	85.10
2020	766	4.03
Weighted Average EAF		**71.21**

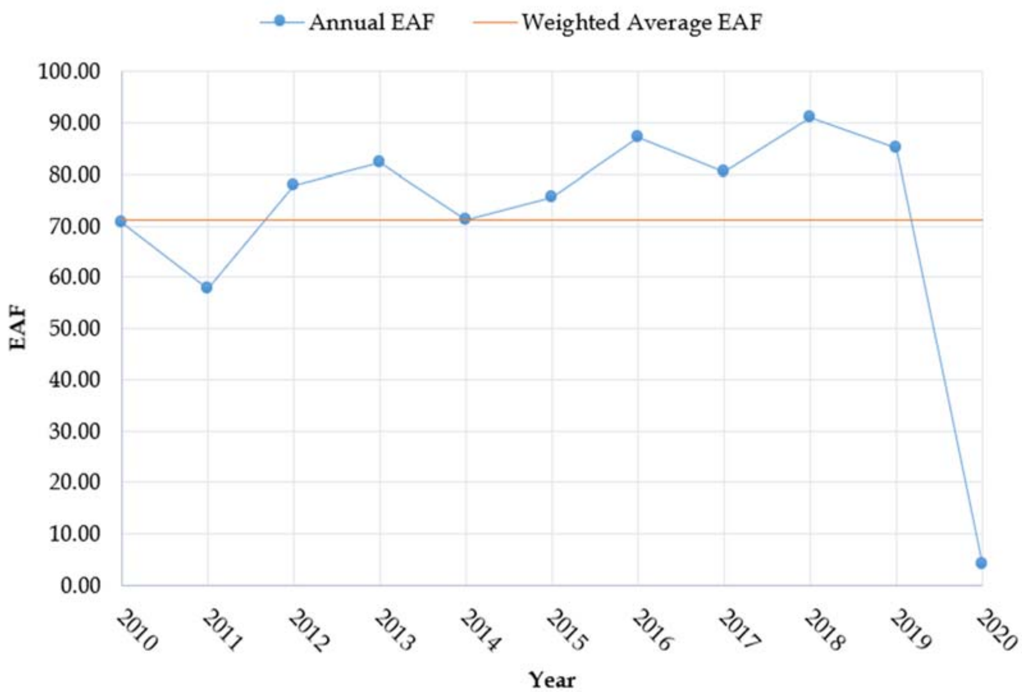


Figure 25. Change in EAF of Comanche 3 from 2010 through October 2020.

Further, when compared to other PSCo-owned coal and gas-fueled units that operate on either a single steam cycle or a combined cycle, Comanche 3 had the lowest weighted average EAF from 2010 through October 2020. Although newer units should be expected to have higher AFs and EAFs compared to older units, the opposite is true for Comanche 3; the Company's older units have a greater weighted average EAF, as shown in Table 7 and Figure 27 below.

Table 7. Weighted average EAF data for PSCo generating units from 2010 through October 2020.

	Unit	Weighted Average EAF
Cherokee	4	74.04
	5	76.81
	6	83.28
	7	78.15
Comanche	1	81.12
	2	76.71
	3	71.21
Fort St. Vrain	1	78.23
	2	80.49
	3	79.64
	4	80.57
Hayden	1	81.24
	2	81.56
Pawnee	-	78.45
Rocky Mountain Energy Center	1	73.27
	2	73.44
	3	73.92

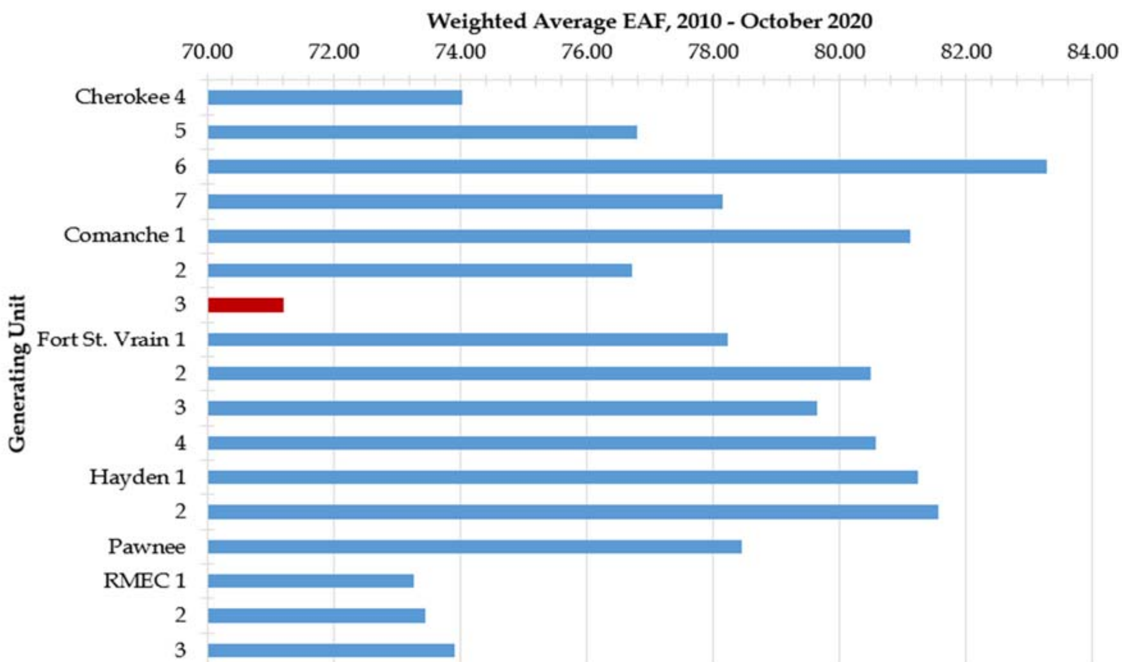


Figure 26. Graphical illustration of weighted average EAF data of PSCo generating units. Note that Comanche 3 clearly has the lowest weighted average EAF of all the units.

Staff compared the EAF of Comanche 3 with that of other similarly sized units across NERC territory using the GADS availability database. The database provides an aggregated EAF of 80.38 for the years 2015 through 2019 for all coal units with a nameplate capacity between 600 MW and 799 MW. By comparison, the EAF for Comanche 3, which has a nameplate capacity of 750 MW, is 83.87 over the same five-year period. Clearly, the EAF for Comanche 3 for the years 2015 through 2019 is greater than the aggregate EAF for other similarly sized coal units in the GADS database. This is in accordance with the industry observation that newer/younger units tend to have greater EAFs than older units once the initial shakedown period is complete.

Data for 2020 has not yet been provided on the GADS database as of this writing, so an analysis including 2020 has not been performed. However, it is reasonable to assume the aggregated EAF of similarly sized units for 2020 is not lower than Comanche 3's EAF of 4.03.

Finally, Staff also used historical hourly generation data for Comanche 3 to determine the general availability without consideration for unit derates (presented as a percentage of hours per year that the unit was online and generating), the actual capacity factors for the unit (based on historical hourly generation data), and the number of days each years that the unit was in an outage condition (zero generation). The results, shown in Figure 28, trend closely to the EAF analysis above.

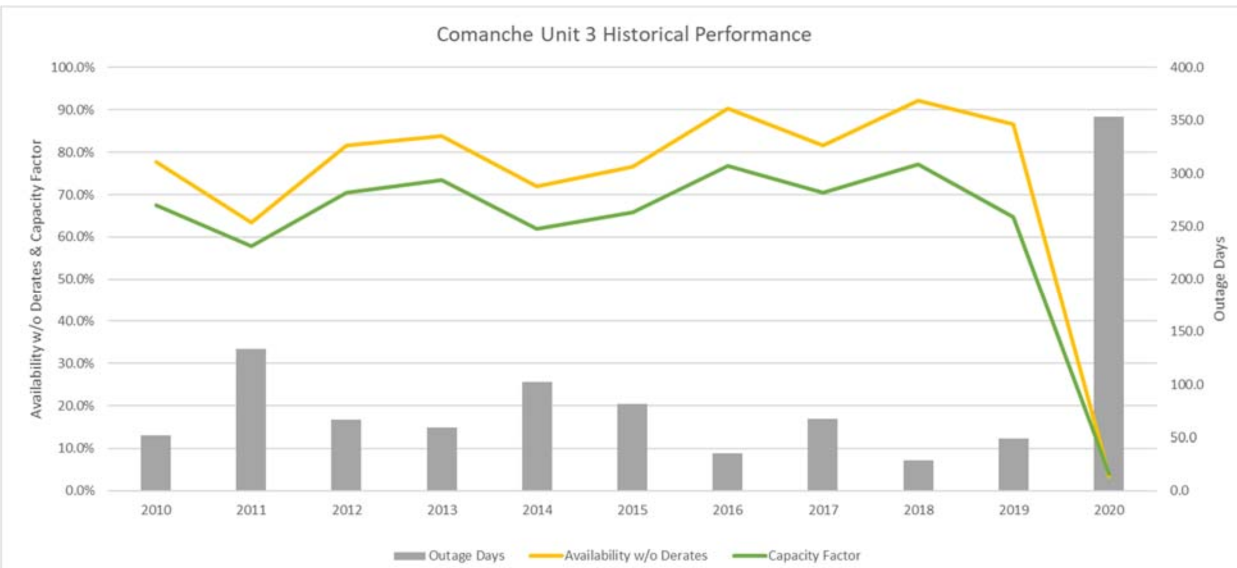


Figure 27. Comanche 3 historical hourly generation data.

C. Capacity Factors

Capacity factors (CFs) differ from availability factors. Whereas the AF measures the fraction of an operating period in which a unit is available to generate electricity without any outages, the CF is a ratio of the amount of power a unit generated over a given period to the theoretical maximum power output possible over that period. For the years 2017 through 2019, the actual net capacity factor (NCF) of Comanche 3 closely matched the modeled CF of the unit using the Electric Commodity Adjustment (ECA) on a year-ahead basis.[122] In 2017 and 2019, the actual NCF was

[122] Confidential Response CPUC5-3.

roughly 95 percent of the modeled CF for those years. In 2018, the actual NCF was approximately 99 percent of the modeled CF for that year.

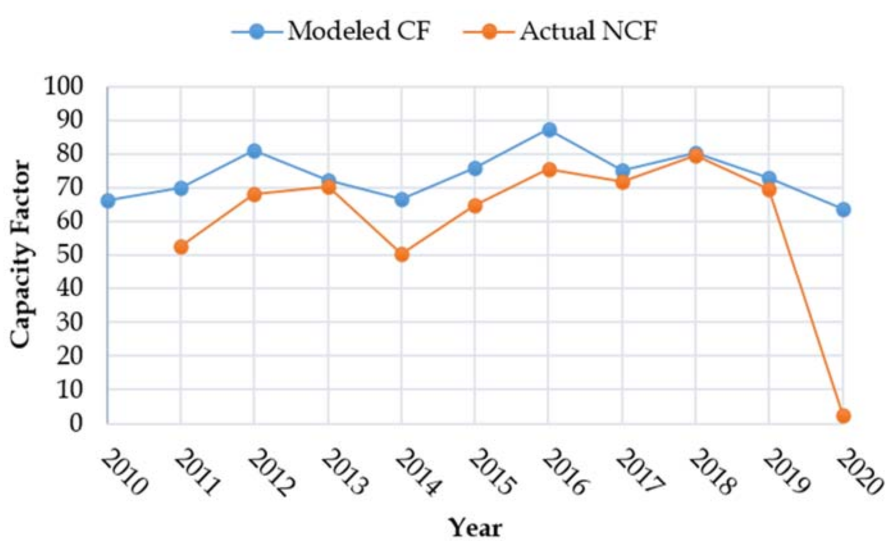
However, the unit's offline status for 2020 dramatically reduced its NCF. For 2020, Comanche 3 had a CF of 2.37, which is just 3.72 percent of its modeled CF of 63.7. It is notable that the actual CF of Comanche 3 was lower than both the modeled CF from the ECA on a year-ahead basis and the modeled CF from the 2007 Electric Resource Plan proceeding, shown later in Table 12. Additionally, the unit had a lower NCF than other older PSCo units in 2020, as shown in Table 8.

Table 8. Comparison of actual capacity factors of all PSCo-owned coal and gas-fueled steam and combined cycle units to Comanche 3.

Units	2020 NCF
Cherokee: Unit 4	33.09
Cherokee: Unit 5	57.24
Cherokee: Unit 6	62.03
Cherokee: Unit 7	53.38
Comanche: Unit 1	70.28
Comanche: Unit 2	65.99
Comanche: Unit 3	2.37
Fort St. Vrain: Unit 1	47.88
Fort St. Vrain: Unit 2	71.80
Fort St. Vrain: Unit 3	71.55
Fort St. Vrain: Unit 4	57.92
Hayden: Unit 1	63.89
Hayden: Unit 2	46.44
Pawnee	69.78
Rocky Mountain Energy Center: Unit 1	64.55
Rocky Mountain Energy Center: Unit 2	66.62
Rocky Mountain Energy Center: Unit 3	49.71

Table 9. Modeled vs. actual capacity factors for Comanche 3, May 2010 – October 2020.

Year	Modeled CF	Actual NCF	% (Actual/Modeled)
2010	66.2	-	-
2011	69.8	52.66	75.44%
2012	80.9	68.13	84.22%
2013	72.2	70.29	97.35%
2014	66.7	50.54	75.77%
2015	76.0	64.64	85.05%
2016	87.2	75.56	86.65%
2017	75.3	71.89	95.47%
2018	80.2	79.46	99.08%
2019	72.9	69.65	95.54%
2020	63.7	2.37	3.72%



VI. Overall Costs Compared to Original Expectations

A. Estimated Levelized Cost of Energy

The components of Comanche 3's revenue requirements by year are shown in Table 10. The annual generation totals in gigawatt-hours (GWh) for Comanche 3 are listed in the second column. Operations and maintenance (O&M) includes the costs for labor, water, chemicals, property rents, ash handling, SO_2 allowances, and other miscellaneous costs for services and materials required to operate and maintain Comanche 3. These O&M costs do not include the capitalized maintenance and repair costs described in the previous section. The O&M costs in Table 10 also include "fuel handling costs," which are the O&M costs related to the Coal Handling Assets used to unload, stockpile, crush, reclaim, move, and deliver coal for use at the station.[123] Fuel expenses are for the purchase of coal and its transportation to be burned in the facility.

The next two columns, depreciation and rate base return, are calculated from the unit's capital balance. Depreciation reflects the wear and tear on Comanche 3's physical equipment, and the capital costs are paid off by passing depreciation expenses through to customers over time.[124] The return on rate base represents the "fair value" return given to the capital owners, and is calculated by multiplying the regulated rate of return by the plant in service balance. PSCo's weighted-average regulated rate of return during 2010-2020 was 7.89 percent. This rate of return is the primary income on which taxes are paid to the federal and state government, shown in the second to last column of Table 10.

The levelized cost of energy (LCOE) for Comanche 3 can be calculated from the revenue requirements data presented in Table 10. The LCOE is equal to the summation of present value costs divided by the generation (MWh) in the corresponding year, discounted by PSCo's weighted average cost of capital (WACC) and is a standard metric used to compare generation resources with different characteristics. The average LCOE from 2010-2020 for Comanche 3 was $66.25/MWh. If we exclude 2020 from this calculation, which was a particularly unusual year with very little energy production, the LCOE only drops to $63.72/MWh. Figure 30 breaks out the $66.25/MWh LCOE calculation into its cost components, including fuel,

[123] Confidential Response CPUC11-3b,ii.

[124] The ongoing depreciation expenses reported in Table 10 incorporate a reduction for previously-recovered costs from the allowance of funds used during construction (AFUDC).

Table 10. Comanche 3 revenue requirements by year, nominal dollars ($ in millions).[125]

Time Period	GWh	O&M	Fuel	Depreciation	Rate Base Return	Income Tax	Total
2010	2,182	$20.8	$31.7	$11.0	$77.2	$33.9	$174.5
2011	2,467	$36.0	$35.5	$17.8	$73.1	$32.4	$194.8
2012	2,981	$34.3	$47.7	$17.5	$66.6	$29.2	$195.4
2013	3,100	$35.0	$48.1	$17.7	$62.4	$27.3	$190.5
2014	2,494	$38.7	$36.4	$17.8	$60.3	$26.4	$179.6
2015	2,730	$35.9	$37.4	$18.0	$54.8	$25.4	$171.4
2016	3,196	$35.6	$43.0	$18.2	$52.2	$24.1	$173.0
2017	3,120	$37.2	$40.9	$18.2	$50.4	$23.8	$170.4
2018	3,373	$35.1	$43.7	$18.1	$48.9	$11.9	$157.8
2019	2,830	$35.2	$37.3	$18.2	$47.5	$11.5	$149.5
2020	103	$39.0	$1.6	$17.3	$44.7	$13.9	$116.6
Total	28,576	$382.7	$403.4	$189.7	$638.0	$259.6	**$1,873.5**

depreciation, O&M, regulated return, and income tax. Both Table 10 and Figure 30 show that the regulated return earned on capital has been the largest of these categories in contributing to Comanche 3's revenue requirement over the past 10 years.

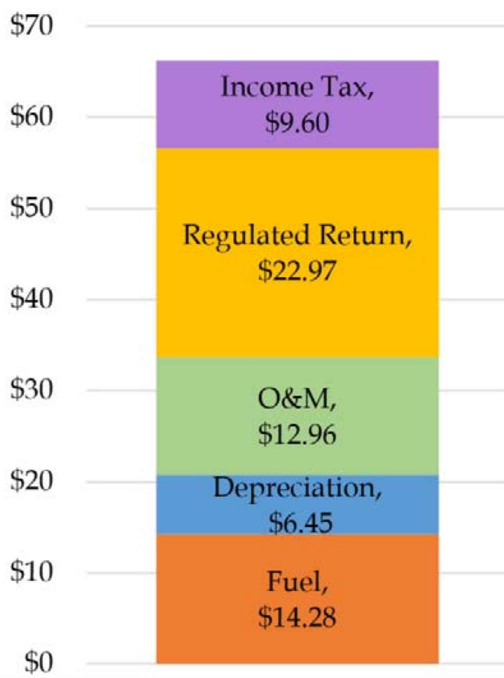


Figure 28. Comanche 3 LCOE components ($/MWh), 2010-2020.

[125] Confidential Attachment CPUC3-4a.A1.

Table 11 shows the capital costs incurred to date for Comanche 3 in nominal dollars, provided by PSCo through Audit. PSCo spent approximately $784 million in upfront capital between 2004-2010.[126] Capital costs displayed for 2011 onward will be referred to as "incremental capital," which have totaled $72 million to date. These incremental capital costs are a source of concern for Staff because it appears they were not included in PSCo's modeling assumptions for the resource planning proceeding that resulted in Comanche 3 approval.[127] These costs determine in part the unit's capital balance, from which depreciation and the regulated return are calculated. All these capital costs are not immediately passed through to retail ratepayers but are paid off over time via depreciation expenses. The Company has additionally collected a 7.89 percent average WACC return on these capital costs from 2010-2020. PSCo's latest WACC as of 2020 is 6.98 percent.

Table 11. Comanche 3 incurred capital costs, nominal dollars.

Time	Capital Costs
2004-2010	$784,260,737
2011	($7,413,091)
2012	$12,444,753
2013	$5,898,033
2014	$7,675,280
2015	$13,866,003
2016	$2,316,319
2017	$12,640,424
2018	$926,829
2019	$4,636,569
2020	$19,181,066
Total	**$856,432,922**

Table 11 shows a total Comanche 3 capital balance of $856 million. As of 2020, Comanche 3's total plant in service balance was $975 million. Much of this difference is due to capitalization of the cost of borrowed funds used during construction, or allowance for funds used during construction (AFUDC). These are costs not included in Table 11 but are part of the total plant in service. [128]

[126] Confidential Attachment CPUC11-1.A1.

[127] Staff asked the Company to provide the full set of Strategist modeling inputs and outputs as well as workpapers for Comanche 3 revenue requirements used in its 2003 Least Cost Plan Proceeding (consolidated Proceeding Nos. 04A-214E, 04A-215E and 04A-216E), but PSCo responded that it was unable to locate those files (response to Confidential Response CPUC3-1). The Company did provide references to some other documentation of certain modeling assumptions, but there is no indication that incremental capital costs were included for modeling purposes. PSCo staff also verbally confirmed that Comanche 3 was primarily examined on a "cost-to-construct" basis and therefore incremental capital was likely not considered.

[128] The list of capital costs, as well as a reconciliation between capital costs and the plant in service values are provided in Confidential Attachment CPUC10.1e.

The negative capital value reported in 2011 resulted from the reversal of a $23 million accrual PSCo had previously booked for Comanche 3 due to a lawsuit brought by the Balance of Plant contractor related to accessory electrical equipment. The accrual was reversed in 2011 after PSCo won the lawsuit. Other large incremental capital costs for unit 3 include over $10 million spread across the decade for work on the selective catalytic reduction (SCR) system, mostly related to catalytic layer replacements. In 2015, the turbine feedwater superheater was replaced at a cost of $11.6 million. The relatively larger capital costs in 2017 were due in part to the previously-mentioned SCR work, a replacement of fabric filter dust collector (FFDC) bags at $1.3 million, a boiler upper wall replacement at $1.5 million, and a software and control system upgrade project costing $1.9 million.

PSCo also undertakes capital projects that are common to all Comanche units. The costs for these "common" projects are also allocated in part to unit 3. Examples of large common capital costs allocated to Comanche 3 include $3.3 million towards a maintenance building in 2010-11, $3.7 million for a coal pile wind fence in 2012, $3.6 million to upgrade the plant's lime feed system during 2013-15, and $3.2 million for a replacement of the plant's ash disposal cell liner, mostly incurred in 2017.

B. Comanche 3 in Rate Base

Comanche 3's cost in PSCo's rate base was $885 million in 2010. This is determined by transferring all the costs of construction work to the rate base account, except for the pre-funded AFUDC costs. The rate base balance is paid off over time using the PUC-approved depreciation expenses passed through to ratepayers. In this way, the approved depreciation schedule determines how quickly Comanche 3 is "paid off," or amortized over time. As of 2020, Comanche 3's rate base stood at $633 million. Comanche 3's rate base by year is shown in Figure 31, including a projection to 2030. Assuming historic trends continue, the rate base will be $460 million in 2030, $389 million in 2035, and $320 million in 2040. Comanche 3's PUC-approved depreciation schedule assumed a 60-year lifetime, so that the asset would be fully depreciated around 2070.[129] If Comanche 3 were to retire earlier, the remaining balance would need to be recovered from ratepayers or written off of PSCo's books if disallowed.

[129] Reference Lisa Perkett Direct Testimony in rate case proceeding No. 08S-520E

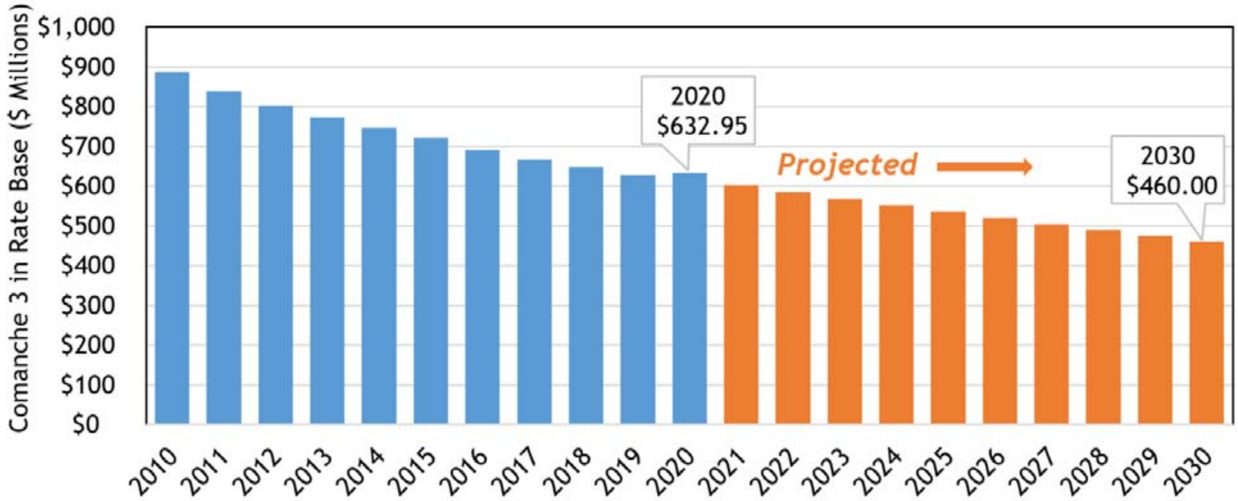


Figure 29. Comanche 3 costs in PSCo rate base, historic and projected.

This Comanche 3 rate base projection was created by Staff for illustrative purposes. More detailed analysis should be done before deciding changes to a depreciation schedule or making other important decisions based off this information. The projection assumes Comanche 3 incremental capital additions and retirements equal to the average level from the past 8 years.[130] It is possible that incremental capital amounts will be different in future years. Additionally, the rate base includes deductions for deferred income taxes. Tax rules allow for accelerated depreciation schedules relative to PUC-approved depreciation for purposes of federal income tax deduction. This has the effect of deferring Comanche 3's federal tax obligations to future years, which is similar to a zero percent interest loan from the federal government. Utility accounting rules require the removal of this benefit from rate base under an accumulated deferred income tax (ADIT) line. The ADIT deduction will decrease over time as the PUC depreciation schedule catches up to the accelerated schedule. For simplicity, Staff assumed a cost curve that declined at the rate from the past 10 years for projecting future ADIT. Future ADIT might be different than what Staff projected because depreciation rules change over time. For example, the recent federal Tax Cuts and Jobs Act included substantial revisions to federal tax depreciation rules.

Examining these historic costs raises the question of the *reasonableness* of costs for the facility. We address this question through two primary means: 1) by comparing the actual costs with the costs initially projected by PSCo when the Company sought approval to build the unit, and 2) by comparing actual costs with costs incurred by other similar plants during a similar time period. These comparisons uncovered three primary issues:

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[130] Incremental capital from the first two years of operation were omitted because they were significantly higher than later years and may be related to non-typical work conducted around the unit start-up period.

I. First, as discussed above, PSCo's projections apparently did not contemplate the incremental capital expenses that have been incurred for Comanche 3 since it began commercial operation. This is concerning as Comanche 3 has incurred substantial incremental capital cost since commercial operation, previously described in Table 11. Some of these costs are typical of all fossil steam plants and should have been expected by PSCo and conveyed to the Commission upfront. Expected costs include the incremental capital costs related to Comanche 3's pollution control equipment.[131]

II. The second issue is that Comanche 3's actual O&M costs have been much higher than initially projected and have also been higher than O&M costs incurred at older fossil steam plants around the country.

III. Third, PSCo's upfront capital cost projection was $680 million,[132] compared to actual upfront costs of approximately $784 million. This does not include the $72 million in incremental capital costs that have been incurred between 2011 and 2020.

Comanche 3's fuel costs have been somewhat lower than what was initially projected, but this is explained by the fact that Comanche 3 has operated much less than anticipated. On a $/MWh basis, PSCo's early fuel costs projections were quite close to Comanche 3's actual fuel costs.

C. O&M Costs

PSCo's 2007 ERP assumed Comanche 3's fixed O&M costs would start at $14.7 million annually and variable O&M at $1.75/MWh, both escalating at approximately 2 percent per year.[133] These O&M cost projections are significantly lower than what has actually been incurred at Comanche 3. PSCo's financial accounts don't differentiate between fixed and variable O&M, so the aggregated O&M projections from the 2007 ERP model are compared with actual aggregate O&M costs in Table 12. From 2010-2020, projected total O&M costs were $24.16 million per year, compared to actual O&M costs of $34.79 million per year. This difference is particularly stark since Comanche 3 has produced much less energy than what was projected, and O&M costs partly scale with production. The resource planning modeling assumed an average capacity factor of 91 percent from 2010-2020, compared to Comanche 3's actual capacity factor of 59 percent. Excluding 2020, the capacity factor from 2010-2019 was 65 percent. One takeaway from this comparison is to focus on ensuring that the ERP modeling for Comanche 3 is more solidly based on historic evidence in future ERP proceedings.

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[131] For example, this study commissioned by the EPA characterizes the upfront and ongoing costs typically associated with SCR equipment. This particular study was published in 2017, but references similar studies in the past that have SCR cost estimates from 2004-2006, as well as 2010 and 2013. https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf

[132] Confidential Attachment CPUC3-1a.A1.

[133] These O&M cost numbers are derived directly from PSCo's 2007 Strategist model output files.

Table 12. Projected versus actual O&M costs ($ in millions).

	Projected O&M	Actual O&M	Projected CF	Actual CF
2010	21.85	20.76	94%	50%
2011	22.31	36.01	94%	53%
2012	22.08	34.34	84%	68%
2013	23.28	35.02	94%	70%
2014	23.79	38.70	94%	61%
2015	23.56	35.86	85%	65%
2016	24.88	35.56	94%	76%
2017	25.39	37.16	94%	72%
2018	25.12	35.10	85%	79%
2019	26.48	35.20	94%	70%
2020	27.06	39.03	94%	2%
Average	**24.16**	**34.79**	**91%**	60%

It also is instructive to compare Comanche 3's costs with similar units elsewhere in the industry. While particular plant configurations differ across the country, the U.S. Energy Information Administration (EIA) publishes aggregate numbers on O&M costs incurred by power plants over time. A comparison of Comanche 3's historic O&M costs with the national average for fossil fuel steam plants[134] is provided in Figure 32. It shows O&M costs higher than the average for the first several years of operation, followed by a convergence in recent years. Over this 10-year period, average O&M costs for Comanche 3 were $12.07/MWh, compared to a national average of $9.77/MWh.[135] While it may seem promising at first glance that Comanche 3 has matched the national average in recent years, it's important to keep in mind that US coal plants are generally much older than Comanche 3. Most existing coal plants were built between 1950 and 1990, with an average coal plant age of approximately 40 years.[136] Staff is surprised Comanche 3 is not doing better on O&M costs than the rest of the country's older coal fleet.

[134] The EIA definition for the fossil fuel steam plant category is "An electricity generation plant in which the prime mover is a turbine rotated by high-pressure steam produced in a boiler by heat from burning fossil fuels."

[135] Comanche 3's average O&M costs in 2020 were $379/MWh. These are excluded from the comparison for obvious reasons. This high average value is because Comanche 3 incurred fixed costs similar to previous years, but it only produced for a couple weeks at the beginning of the 2020.

[136] https://www.eia.gov/todayinenergy/detail.php?id=30812

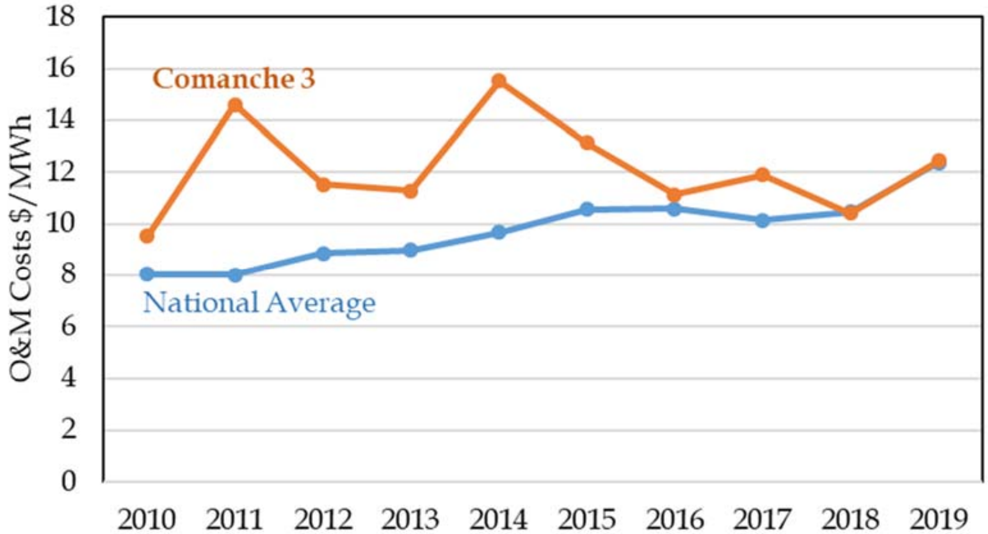

Figure 30. O&M costs, Comanche 3 compared to national average. Source: EIA. [137]

D. Capital Costs

The most detailed early capital cost projection Staff obtained was from a 2003 sharing settlement agreement between PSCo, IREA, and HCE. [138] The estimated upfront capital costs were $607 million for PSCo's share of unit 3, plus an additional $73 million for projects common to the whole plant.[139] This cost projection is summarized in Table 13.

[137] EIA: "Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 2009 through 2019," https://www.eia.gov/electricity/annual/html/epa_08_04.html

[138] Confidential Attachment CPUC3-1a.A1.

[139] Confidential Response CPUC13-19, the Company states that none of the 2020 equipment work was covered under warranty.

Table 13. PSCo upfront capital cost projections, 2003.

Comanche 3 Unit Specific		
Steam Turbine Generator Area	$	47,187,333
Boiler Area	$	216,780,333
Fuel & Ash Area	$	20,183,333
Electrical and I&C Area	$	39,681,333
AQCS Unit III	$	59,942,667
Unit Specific - Yard Area	$	55,706,667
Direct Costs Adjustments & Indirect Costs	$	167,418,576
Unit Specific Subtotal	**$**	**606,900,242**
Project Common Facilities		
Project Site Development & Utilities Area	$	5,404,284
Coal Handling System	$	3,290,780
Water & Wastewater Treatment Area	$	12,737,376
Yard Area	$	27,988,085
Yard Electrical and Security	$	3,467,660
Direct Costs Adjustments & Indirect Costs	$	20,147,517
Project Common Subtotal	**$**	**73,035,702**
Grand Total	**$**	**679,935,944**

These projections can be compared to an actual $784 million of capital costs for Comanche 3 from 2004-2010. These costs are summarized in Table 14. Some of the rows in Table 14 appear comparable to the project descriptions provided in the Table 13 categories, including potentially those related to the boiler equipment, turbogenerator, and electrical equipment. However, from the reporting obtained by Staff, it is difficult to directly compare particular rows within these two tables due to differences in labeling of individual capital projects across the sources used to derive these costs.

Table 14. Comanche 3 upfront capital costs, 2004-2010.

Comanche 3 Unit Specific		
Boiler Plant Equipment, Initial Construction	$	390,381,954
Accessory Electrical, Initial Construction	$	90,248,446
Structures and Improvement, Initial Construction	$	94,728,559
Turbogenerator	$	128,595,375
Miscellaneous Capital	$	15,292,225
Unit 3 Subtotal	**$**	**719,246,559**
Project Common Facilities		
Maintenance Building	$	3,119,854
Miscellaneous Capital	$	61,894,324
Project Common Subtotal	**$**	**65,014,178**
Grand Total	**$**	**784,260,737**

* Note: The Boiler Plant Equipment Initial Construction account has an additional $11.1 million reported during 2011-2012.

In addition to these upfront costs, Comanche has incurred $72 million in nominal incremental capital costs between 2011-2020 as previously described. These incremental expenditures were not contemplated in PSCo's projections. The capital costs are paid off by PSCo ratepayers over time through a depreciation expense. Staff estimates the annual depreciation expense associated with PSCo's upfront capital projection listed in Table 13 would have been $13.1 million,[140] compared to an actual average annual depreciation expense of $17.2 million during 2010-2020. This difference is due to the incremental capital as well as the upfront capital costs that were higher than projected.

E. Fuel Costs

In hindsight, during 2010-2020 fuel costs incurred for Comanche 3 were 34 percent lower than what was projected in PSCo's 2007 ERP. This difference is almost entirely explained by the fact that Comanche 3 has produced less electricity than was initially projected, leading to lower fuel costs. However, on a normalized basis, PSCo's projected average fuel costs were $13.83/MWh, compared to an actual average fuel cost of $14.12 from 2010-2020. This is an impressively accurate fuel cost projection on a $/MWh basis.

[140] Staff made this estimate because PSCo lost and was unable to provide its more detailed revenue requirement projections from before Comanche 3 was built. Staff calculated the average depreciation expense as a portion of the total plant in service from 2010-2020 as an approximation, which was 1.92%. This estimate is equivalent to a 52-year straight line depreciation schedule. 1.92% of $680M is $13.1M.

F. Coal Supply

As noted above, the total price of coal for Comanche 3 has been very close to the original projection from the 2007 ERP, Proceeding No. 07A-447E. Figure 33 below shows the Comanche fuel price forecast for the last three ERP proceedings as well as the actual weighted average annual price for fuel delivered to Comanche. This chart shows that the price for coal delivered to Comanche for the first five years of operation was at or above the initial forecast while in recent years, the delivered price has been below forecast. All prices shown include the price for the coal fuel and transportation but do not include fuel handling costs.[141]

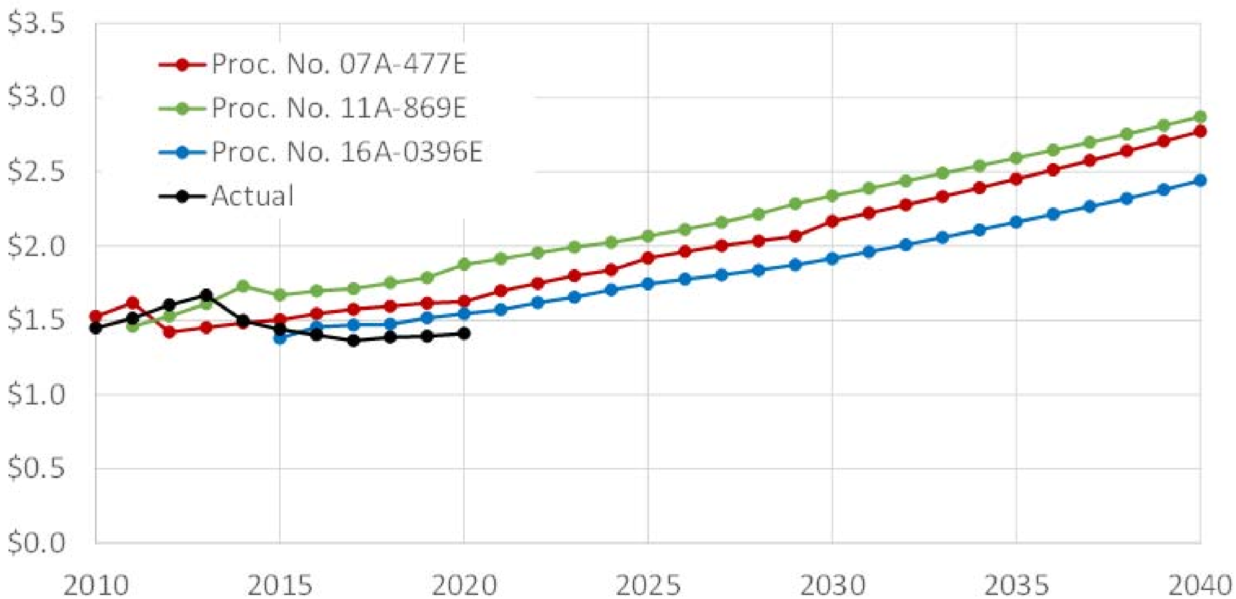

Figure 31. Forecast vs. actual average fuel cost ($/MMBtu delivered).

The coal supply for all three Comanche units generally comes from three mines all located in the Powder River Basin in Wyoming. Table 15 shows a summary of the location of coal supply since Comanche 3 started operating in 2009 as well as a breakdown of contract versus spot coal. For the first eight years of operation (2009 through 2016) the Company relied almost exclusively on contract coal. Over the last four years (2017 through 2020) the Company has shifted to a mix of approximately one third spot coal and two thirds contract. Comanche coal delivery contracts varied in length from under a year to as long as four years with the majority of the contracts being one to three years in length.

[141] Coal fuel is approximately 55% of the total delivered cost while transportation is approximately 45%.

Table 15. Location of coal supply and breakdown by contract vs. spot coal.

Coal Mine	Contract Coal	Spot Coal	Total
Antelope (WY)	19%	0%	19%
Belle Ayr (WY)	48%	3%	51%
Black Thunder (WY)	21%	7%	28%
Other	1%	1%	2%
Total	89%	11%	100%

Currently, the Company has some coal contracted for delivery to the Comanche facility through June of 2022.[142] In addition, the Company has a contract for delivery of coal to Comanche with BNSF railroad through December of 2031. The coal transportation contract requires that 95 percent of the coal delivered to Comanche be covered by the BNSF contract with a maximum of 6 million tons per year. There is no minimum coal transport requirement.[143]

[142] Confidential Attachment CPUC6-8.A.
[143] Confidential Attachment CPUC6-2.A18 and Confidential Attachment CPUC6-2.A17.

VII. Implications in Future Regulatory Proceedings

A. Modeling in 2021 ERP and Clean Energy Plan Proceedings

i. Modeling

It is clear that the Commission will be considering the potential early retirement of coal-fired generation in the Company's upcoming Electric Resource Plan and Clean Energy Plan that is anticipated to be filed on or before March 31, 2021. The Commission in rulemaking Proceeding No. 19R-0095E, Decision No. C20-0207-I, Attachment B has proposed Rules 3604(l) through 3604(n), and Rule 3607(c) which would appear to apply directly to the information and findings presented in this report. Specifically, these rules state:

> **3604. Contents of the Electric Resource Plan.**
>
> The utility shall file an electric resource plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following.
>
> […]
>
> (l) An assessment of potential cost-effective early retirements of utility-owned resources with retirement dates during the planning period, including the costs associated with incremental depreciation expenses and estimated operational and capital savings. For each early retirement reviewed, the utility shall describe the replacement resource need, possible system reliability impacts, and corrective actions for such impacts. (m) An assessment of the costs and benefits of early retirements of utility-owned resources and the acquisition of new utility resources required to reduce the carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030.
>
> (n) A proposed base case portfolio of resources and at least one proposed alternative portfolio of resources to calculate and to present the associated net present value of revenue requirements using the cost of carbon emissions calculated by the Commission pursuant to rule 3552. The utility also may propose different costs

of carbon emissions to be used with respect to the alternative portfolios of resources.

(o) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, consistent with the amounts of renewable energy resources the utility proposes to acquire.

3607. Assessment of Existing Resources.

[…]

(c) Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing supply-side resources greater than 20 MW of nameplate capacity to the costs and performance of the generic resources.

It is essential in the upcoming resource planning proceeding that modeling of the Comanche 3 unit is consistent with the historical information documented within this report including unit availability, O&M costs, incremental capital costs, etc., in order to reasonably determine the appropriate retirement date for the unit.

In modeling for most previous Electric Resource Plans, existing Company-owned generation was assumed in all scenarios to continue operating in accordance with economic commitment and dispatch for the remainder of its useful life. This generally meant that the assumptions for those units had limited impact on the modeling results because their cost and performance were similar across scenarios and portfolios. However, because the forthcoming ERP/CEP will compare differing early retirement scenarios, these assumptions can significantly impact the modeling outcomes.

PSCo has indicated that its Clean Energy Plan will model not only different retirement dates, but also different unit operation. In order to meet or exceed GHG reduction targets, some scenarios will utilize unit dispatch that is constrained by operating limits or subject to cost of carbon assumptions. The Company should fully explain all the options considered and how the proposed operation and retirement timing are superior to other options.

As part of this explanation, the Company should describe how it would implement any operating limits and its expectations for how Comanche 3 would actually operate across all operational options considered. It must also provide evidence that the modeling assumptions take into account past performance issues and properly account for heat rate, O&M cost, and emission profile changes consistent with the operations modeled.

To consider when to retire and/or operate Comanche 3 significantly less, it will be critical to correctly characterize which costs can be avoided by the various options. This will require separating fixed and variable O&M, since fixed O&M cannot be avoided by operating the unit less. The Company should provide detailed projections for these fixed and variable O&M requirements, as well as specific CapEx projects and budgets by year for each scenario.

ii. Performance Standard

The significant performance issues at Comanche 3 support Staff's position that Company-owned generation should be subject to a performance standard to ensure it delivers the value proposition that led to its approval. As demonstrated by the high costs to provide replacement power during the lengthy 2020 outage that encompassed the peak summer period, inability to operate company-owned generating assets can impose millions of dollars in extra costs on ratepayers. The actual levelized cost of energy from Comanche 3 during the first 10 years of operation has been substantially higher than the LCOE estimated when the plant was approved by the Commission.[144]

It appears likely that PSCo's Clean Energy Plan will lead to significant additions of Company-owned generation. Before approving any specific Clean Energy Plan portfolio, the Commission should establish a performance standard for both existing and new Company-owned units, regardless of technology, to protect ratepayers from the potential for poor performance or unreasonable costly unexpected investments. In addition, the Commission should carefully consider performance standards for any new Company-owned generating assets approved in the upcoming ERP. The Commission, Commission Staff, the Company and interested parties should consider what form of performance metrics and guarantees are appropriate for existing Company-owned resources and the best procedural path for introducing and discussing such options.

B. 2020 Electric Commodity Adjustment Prudence Review

The extended and unexpected outage of Comanche unit 3 for essentially the entirety of year 2020 resulted in short and medium-term market purchases to replace the energy and capacity of the Company's largest single generating asset. The outage also at times resulted in the operation of more expensive Company-owned system resources. The costs of this replacement power, both the market purchases and owned-unit operations, are included in the calculation of the quarterly Energy Cost Adjustment ("ECA"). The prudence review for these expenses does not occur at the time when the costs are included in the fuel rider, but rather the prudence review will occur when Public Service files its annual ECA prudence review application at the beginning of August 2021.

[144] The forecasted LCOE was $45.70, while through 2020 the actual LCOE was $66.25/MWh.

This ECA prudence review has been contested each of the last two years (Proceeding Nos. 19A-0425E and 20A-0327E). The Settlement reached in the most recent prudence review[145] included an agreement by the Company to provide additional reporting regarding hourly loads, prices and all resources used to serve retail load as well as GADS availability data for the applicable ECA period. This additional data will go a long way to understanding the impact of outages such as the 2020 Comanche 3 events, However, Staff also recommends that, in the upcoming 2020 ECA prudency review, the Company include a complete accounting of the replacement power actions and costs associated with the Comanche outages.

C. Phase I Electric Rate Case Proceeding

The review of costs related to Comanche 3 for everything other than fuel is accomplished in a Phase I rate review proceeding. These costs include the return on rate base including capital additions, fixed and variable O&M expenses, taxes, and depreciation expense. Normally, a Phase I rate review proceeding examines costs incurred since the last rate proceeding and does not re-visit a review of costs that had been incurred and included in a previously approved revenue requirement. Most of the current costs associated with Comanche 3 have been reviewed in previous rate review proceedings.[146]

The next Phase I rate review Proceeding will include the review of any incremental capital additions associated with Comanche 3 since the end of the last Phase I test year. In addition, the test year used in the rate review will include O&M expenses for Comanche 3 incurred during the test year period. Staff recommends that the Company provide separate work papers that detail any revenue requirement components that include Comanche 3 costs. These work papers should, at a minimum, show the amount of Comanche 3 in rate base, any and all capital additions since the last Phase I Proceeding, and the O&M expenses included in the revenue requirement.

D. Future Depreciation Studies

The fixing of appropriate depreciation rates in a duty of the Commission pursuant to C.R.S., §40-4.112. The Commission has generally established the appropriate depreciation rate base on the principle of intergenerational equity. The principle established that the period for cost recovery of an investment should correspond to the time it is actually in use. According to this "matching principle," customers who "use" an asset should pay for that asset at the time it is used.

[145] Hearing Exhibit 106, Unopposed Comprehensive Settlement Agreement, in Proceeding No. 20A-0327E.

[146] The most recent electric rate review was conducted in Proceeding No. 19AL-0268E. Comanche 3 costs included in rate base and reflected in the revenue requirement reflect capital additions through the test year period of September 1, 2018 through August 31, 2019 and a 13-month average rate base basis.

It seems likely that the Commission in the upcoming resource planning proceeding may decide to establish a firm retirement date for Comanche 3. If it does so, it has been the practice of the Commission to require adjustment to the depreciation rate used for rate setting to conform to the retirement date established by the Commission. While this is the standard practice, it is recommended that the Commission also consider the findings established in this investigation regarding incremental capital investments. It's essential to consider these incremental capital investments in depreciation rate setting in order to allocate recovery of capital costs fairly to ratepayers who benefit from the Comanche 3 unit.

E. Comanche 3 Follow-up

The decision opening this proceeding specifically established:

> The purpose of this proceeding is to: authorize Staff to investigate the history and ongoing operations of Comanche Unit 3 as discussed above; and receive Staff's report of findings. Any further action will be taken up in future proceedings as appropriate."[147]

Notwithstanding, there is ongoing reporting that Staff would recommend that the Commission direct as part of this proceeding:

- The Commission should direct the Company to file quarterly status reports, into this investigatory proceeding confirming the completion of those actions recommended by its own investigatory teams or an explanation as to why the recommendations were not adopted; and

- The Commission should direct the Company to file monthly reports for each of the months October through May, due 10 days after the end of each month, documenting all unplanned outages for Comanche 3 in the prior month, with a brief description of the cause of each outage and the actions taken during the outage.[148]

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[147] Decision No. C20-0759, ¶14.

[148] The Company already provides Staff daily reports during the months of June regarding the status of the entire generation fleet pursuant to Commission Decision No. R96-517. As a result, no additional outage reporting during these months is necessary.

The observations, findings and recommendations included in this report are those of the Staff of the Commission participating in this investigation and are not to be construed as being the observations, finding or recommendations of the Colorado Public Utilities Commission or of any individual Commissioners.

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Public Utilities Commission