BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-26-21 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-151:
WECC Contingency Reserve Whitepaper

WECC

# WECC-0142 BAL-002-WECC-3

Contingency Reserve

Request to Retire

WECC-0142 Drafting Team

01/21/2025

## Executive Summary

This document supports and requests full retirement of WECC Regional Reliability Standard (RRS) BAL-002-WECC-3, Contingency Reserve.

In FERC Order No. 672, when considering approval of RRSs, FERC agreed to accept two kinds of regional differences: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) an RRS that is necessitated by a physical difference in the Bulk-Power System.[1]

Order 672 also provides authority to retire an RRS.

Since the start of BAL-002-WECC-3 and its predecessors (2007), the original standard and each subsequent iteration have continued as more stringent than the continent-wide equivalent, NERC BAL-002-X, Disturbance Control Standard. Among other things, WECC's BAL-002-WECC has always required most WECC entities to hold more reserves than the continent-wide equivalent. Specifically, BAL-002-WECC-3, Requirement R1.1.1 requires the applicable entity to hold the greater of, either the amount of Contingency Reserve equal to the loss of the most severe single contingency or the amount of Contingency Reserve equal to the sum of 3% of hourly integrated load and 3% of hourly integrated generation.

Though Requirement R1.1.1 was approved in BAL-002-WECC-1, that approval was predicated on distributing burden and the availability of deliverability.[2] There has never been a technical study proving that holding reserves more than required under NERC BAL-002-X enhances the reliability of the Western Interconnection.

By contrast, as variable generation is added to the Interconnection, there is increasing evidence that holding excess reserves may be inhibiting reliability across the interconnection. FERC's recent Order 901 echoes these concerns, addressing operational and performance concerns for variable resources.

Restated, within the Western Interconnection, applicable entities are holding more reserves than the rest of the continent, even though there is no technical basis for doing so. In FERC Order 693, in which NERC BAL-002-1 was first approved, at P341, FERC states:

> 341. We believe a continent-wide contingency reserves policy would assure [sic] that there are adequate magnitude and frequency responsive contingency reserves in each Balancing

[1] Order No. 672 at P 331. See also FERC Order 740, P 4 and P 23. https://www.nerc.com/pa/Stand/Resources/Documents/FERC'S_Criteria_for_Approving_Reliability_Standards_from_Order_672.pdf

[2] FERC Order 740, Remand.

> Authority. This will improve performance so that no Balancing Authority will be doing *less than its fair share*." (Emphasis added.)

By extension, retiring BAL-002-WECC-3 in favor of NERC BAL-002-3, ensures that no Balancing Authority will be doing **more** than its fair share.

Further, requiring Balancing Authorities to hold that excess may be inhibiting the integration and use of variable generation. As a result, BAL-002-WECC-3 creates a mandated scenario in which reserves are used inefficiently and withheld from the marketplace.

# Table of Contents

## Introduction

Per the Standard Authorization Request (SAR) for WECC-0142,[3] this document explores the full retirement of WECC RRS BAL-002-WECC-3, Contingency Reserve.

The following will show that, if the standard is retired, reliability will continue to be maintained through NERC BAL-002-3, and may be enhanced as resources being held for contingency reserves may be used more efficiently to support variable generation.

By retiring BAL-002-WECC-3 in favor of NERC BAL-002-3:

- Dispatchable resources can be used to support variable generation, addressing issues raised by FERC in Order 901.
- A more efficient use of resources should negate any current negative impacts on the market, thereby enhancing vital public interests.

As the Procedural History and Development History sections note, BAL-002-WECC-3 is an evolution of pre-standards originating in the 1990s. Never during the estimated 30 years of its existence has there been a technical justification for the values and procedures required in the standard. Rather, the stated values and procedures are the result of generalized negotiations taking place between the parties. Because these values and procedures are negotiated, the content of BAL-002-WECC-3 is the lowest common denominator and does not meet the requirements of FERC Order 672.[4]

Because BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 provided the technical support for retiring Requirement R2, arguments in that filing are not revisited here.[5]

[3] See WECC-0142 BAL-002-WECC-3, Contingency Reserve, Request to Retire, home page, at the SAR accordion.
[4] FERC Order 672, P329 and P330.
[5] Approved by the NERC Board of Trustees on August 15, 2019, filed with FERC on September 9, 2019.

## Standard of Review

While the Commission may approve an RRS that is more stringent than a parallel continent-wide standard, the Commission may also retire such a standard.[6]

> "While a Regional Entity may propose regional Reliability Standards that address specific, unique regional conditions and circumstances, *such regional Reliability Standards can be retired if those justifications are no longer relevant.* Accordingly, the Commission may approve retirement of a more stringent regional requirement "if the Regional Entity demonstrates that the continent-wide Reliability Standard is sufficient to ensure the reliability of that region."[7] (Emphasis added.)

In doing so, the Commission must give due weight to the technical expertise of a Regional Entity, like WECC, that is organized on an interconnection-wide basis with respect to the regional differences applicable to the Western Interconnection.

The technical qualifications of the subject matter experts compiling this paper are provided with this filing, as presented and approved by the WECC Standards Committee (WSC).

[6] The Commission approves regional differences proposed by Regional Entities, such as Regional Reliability Standards and Variances, if the regional difference is just, reasonable, not unduly discriminatory or preferential, and in the public interest. 16 U.S.C. § 824o(d)(2) and 18 C.F.R. § 39.5(a). (See also) Additionally, Commission Order No. 672 requires further criteria for regional differences. A regional difference from a continent-wide Reliability Standard must either be:
(1) more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; or is,
(2) necessitated by a physical difference in the Bulk-Power System.

[7] Version One Regional Reliability Standard for Resource and Demand Balancing,
Order No. 740, 75 FR 65964 (Oct. 27, 2010), 133 FERC ¶ 61,063, P 30 (2010). See also: FERC, 18 CFR Part 40, Docket No. RM19-20-000, WECC Regional Reliability Standard BAL-002-WECC-3 (Contingency Reserve), p.5

## Procedural History

In 1996, the Western Systems Coordinating Council (WSCC)[8] adopted the WSCC Reliability Criteria, Minimum Operating Reliability Criteria (MORC). The MORC prescribed levels of reserves that became BAL-002-WECC-3, effective 2021.

In 1999, the MORC became the WECC Reliability Management System (RMS), a contract-based system of accountability that pre-dated mandatory standards.

As the industry approached the onset of mandatory standards (2007) and memorialization of legacy operating practices, the content of the RMS was adapted and approved as BAL-STD-002-0, Operating Reserves (2007). That standard was an attempt to translate the substantive content of the RMS into the sought-after NERC/FERC format of today's reliability standards. The *content* was accepted "as is" with its origins in the 1996 MORC; albeit, the early standard was remanded for remediation, largely on *format* and structural grounds.

In 2013, FERC accepted remediations to BAL-002-WECC-2.

In 2017, an interpretation was added (BAL-002-WECC-2a) and later incorporated into BAL-002-WECC-3, in which Requirement R2 was approved for retirement, with an effective date of August 15, 2019.

In 2025, the Western Interconnection still adheres to similar levels of reserves as it did in 1996. This means that, for over 28 years, the Western Interconnection has held more reserves than the rest of the continent (NERC BAL-002-3) even though there has never been technical justification to do so.

[8] The Western Systems Coordinating Council (WSCC) was formed in 1967 by 40 power systems to coordinate the planning and operations of the electric system in western North America. The WSCC's goal was to provide reliable power to the public.

## Development History (Before 1996 to 2024)

Before 1996, members of the WSCC voluntarily operated the Western Interconnection according to the MORC.[9] Although the MORC contained provisions for generation control, generation performance, and Contingency Reserve, the MORC provided no technical support for the reserve thresholds and characteristics it set.[10] Rather, the operating thresholds were established by negotiation—not technical analysis. If this approach were adopted today, FERC would likely deny approval of the standard as contrary to FERC Order 672, P329.[11]

In July and August of 1996, the Western Interconnection experienced two widespread outages resulting from improper vegetation management. The resulting outage reports[12] [13] made several recommendations that would later be adopted in the 1999 WECC RMS.[14] [15] The WECC Operating Committee's recommendation produced portions of the RMS that later evolved into WECC Standard BAL-STD-002-0, Operating Reserves and, ultimately, BAL-002-WECC-3. Like the other initial

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[9] MORC, Maintenance Coordination: 1. Sharing information. The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of generators, transmission lines and associated equipment, control equipment, communication equipment, relaying equipment, and other system facilities. Entities and coordinated groups of entities must establish procedures and responsibility for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

[10] Minimum Operating Reliability Criterion, Section 1, Generation Control and Performance

[11] FERC Order 672. P329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

[12] The outage reports are available upon request. Western Systems Coordinating Council (WSCC) Disturbance Report for the Power System Outage that Occurred on the Western Interconnection August 10, 1996, as approved by the WSCC Operations Committee on October 18, 1996

[13] "f. The WSCC Operations Committee shall assess whether the levels and allocation of operating reserves contributed to the severity of this disturbance and implement corrective measures as appropriate." Western System Coordinating Council Disturbance Report, For the Power System Outages that Occurred on the Western Interconnection on 2 JUL 1996. Approved by the WSCC Operations Committee on September 19, 1996. RMS Outage Report, page 14.

[14] The RMS was approved 1 SEP 1999. WECC Comment Report – WECC Tier 1- RMS Standard – (BAL-STD-002-0) Question 4, Attachment 2, page 9.

[15] "The majority of these standards were specifically developed to address and mitigate main causes of the two major system outages that occurred in the Western Interconnection in July and August of 1996."  Agenda Item 3, Board of Trustees Meeting, March 12, 2007, page 4

standards, the language of the original standard was a translation of the language contained in the RMS.[16]

In March 1997, noting that federal remedial legislation could take years to enact, the WSCC trustees created the WSCC RMS Policy Group[17] establishing a contract-based operational system known as the RMS.[18] [19] In establishing the RMS, the WSCC RMS Policy Group reviewed all NERC and WECC reliability criteria, identified specific criteria deemed critical for reliability management, then moved those criteria into the RMS through a three-phase implementation plan.[20]

On April 14, 1999, FERC asserted jurisdiction over the RMS.

Between September 1998 and February 2000 (phase two of the three-phase RMS implementation), the WSCC turned the content of the RMS into the first mandatory reliability standards (aka Version Zero, 2007). BAL-SDT-002-0, Contingency Reserve was part of that translation.

On December 22, 2006, WECC submitted a request to NERC to approve, and send to FERC for approval, eight proposed RRSs. WECC referred to the eight proposed standards as its Tier One

[16] WECC states that the proposed regional Reliability Standards, which are exact translations of existing regional criteria, either address matters not addressed in the Commission-approved ERO Reliability Standards or contain more stringent requirements than the ERO standards. (FERC accepted Tier One standards evolving from the RMS. AKA: Tier One Order.) FERC, 119 FERC ¶ 61,260 United States of America, Federal Energy Regulatory Commission, Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications (Issued June 8, 2007), page 19.

[17] Following the enactment of EPAct 2005 and the establishment of mandatory Reliability Standards applicable to all owners, operators, and users of the BPS, WECC sought to translate certain of its existing practices under its RMS reliability criteria into regional Reliability Standards to supplement the continent-wide Reliability Standards the Commission approved in Order No. 693. To that end, WECC established a task force to identify criteria in the RMS that should be binding on all BPS users, owners, and operators in the Western Interconnection, not just the Transmission Operators subject to the RMS. The task force chose eight of the identified criteria, which had the highest priority and could be implemented in the near term for translation into regional Reliability Standards. United States of America Before the Federal Energy Regulatory Commission, North American Electric Reliability Corporation (NERC), Docket No. RM16-10-000, Supplemental Information for Petition of the NERC and WECC for Approval of retirement of Regional Reliability Standard TOP-007-WECC-1a, page 5.

[18] Hearing

[19] Electric Reliability Corporation, Helping Owners, Operators, and Users of the Bulk Power System Assure Reliability and Security for More Than 50 Years, By David Nevius, Senior Vice President 1979–2012, Page 40-41.

[20] Hearing

standards originating from the RMS because the proposed standards were translations of standards that were already mandatory within the Western Interconnection as part of the RMS.[21]

Those eight standards—that included Tier One WECC-BAL-STD-002-0 (Operating Reserves)—were near-exact translations of existing WECC criteria that FERC earlier accepted as part of the WECC RMS program.[22] Because the content was a near-exact translation, the format did not match that required by NERC/FERC. This would later lead to a remand of BAL-002-WECC-1 to ensure conformity.

On January 9, 2007, NERC provided WECC with a report of its preliminary findings about the request from December 22, 2006, and provided WECC with a list of required remediations.[23] The request largely addressed styles, formats, and corrections to compliance sections. The NERC Board of Trustees approved the Tier One request subject to remediation and sent the eight proposed standards to FERC with a request for approval.

In June 2007, FERC approved WECC's submittal of eight reliability-crucial Tier One standards, thereby transitioning from the RMS system to that of FERC-approved NERC Reliability Standards.[24] Although earlier versions lacked technical support, FERC agreed with

> "WECC, WIRAB [Western Interconnection Regional Advisory Board] and NERC that approval of [WECC's early BAL] under section 215 would enhance reliability in the Western Interconnection **by making WECC's current practices binding** on all relevant entities in the region and **by strengthening WECC's compliance and enforcement authority.**"[25]

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[21] North American Electric Reliability Corporation, Docket No. RR07-___-000, III. BACKGROUND ON THE DEVELOPMENT OF THE WECC REGIONAL RELIABILITY STANDARDS, Debra A. Palmer of Schiff/Hardin (1666 K STREET N.W., SUITE 300, WASHINGTON, DC 20006) on March 26, 2007.

[22] Loc. Cit. IV. Overview of the Proposed WECC Regional Reliability Standards, page 6.

[23] NERC DECISION APPROVING, WITH CONDITIONS, RELIABILITY STANDARDS PROPOSED BY WESTERN ELECTRICITY COORDINATING COUNCIL, page 2. (Approved by Board of Trustees March 12, 2007)

[24] FERC Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, Docket No. RR07-11-000, (Issued June 8, 2007)

[25] Tier One Order, p. 43. See also, "The proposed regional Reliability Standards would make eight of those RMS criteria binding on the applicable subset of users, owners and operators of the Bulk-Power System in the United States portion of the Western Interconnection, as identified in each proposed standard. The regional Reliability Standards would supplement rather than replace the Commission-approved Reliability Standards developed by the ERO that will take effect in June 2007. Tier One, p. 10.

# Structural Overview of BAL-002-WECC-3

## Purpose

The Purpose of currently effective RRS BAL-002-WECC-3—Contingency Reserve is to provide an RRS specifying "the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions."[26]

The NERC Glossary defines Contingency Reserve as:

"The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan."

## Applicability

BAL-002-WECC-3 applies to Balancing Authorities (BA), unless the BA is a member of a Reserve Sharing Group (RSG), in which case the RSG becomes the applicable entity.

## Requirements

The standard consists of four requirements.

### Requirement R1

- Provides that each BA and RSG must maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, and that the Contingency Reserve must consist of any combination of a list of specified reserve types.

### Requirement R2

- Reserved. Retired, subject to cyclical field tests.

[26] BAL-002-WECC-3, Contingency Reserve, Purpose.

## Requirement R3

- Each Sink BA and RSG must maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

## Requirement R4

- Each Source BA and RSG must maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source BA or RSG.

## Reliability will be Maintained

Upon retirement of BAL-002-WECC-3, reliability will be maintained by NERC BAL-002-3, Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event, reinforced by the enhanced availability of resources currently unavailable under BAL-002-WECC-3.

### Replacing BAL-002-WECC-3 with NERC BAL-002-3 Mitigates Reliability Gaps associated with Variable Generation

As highlighted by FERC in its Order 901, with the growing amount of variable generation replacing more responsive and dispatchable resources, the industry faces the dilemma of how to support these new resources.[27] Unlike traditional resources, much of the new variable generation cannot be quickly dispatched, thus creating a gap in reliability. FERC acknowledged that gap, noting that neither business as usual nor existing reliability standards will remedy this concern. Finally, FERC also recognizes the value that steps taken must apply on a continent-wide basis.[28]

Replacing BAL-002-WECC-3 with the continent-wide NERC BAL-002-3 takes immediate steps towards meeting FERC's concerns.

In Order 901, FERC states:

> "[W]e continue to find that as the resource mix trends towards higher penetrations of IBRs, the need to reliably integrate these resources into the Bulk-Power System is expected to grow, and that the currently effective Reliability Standards do not adequately address IBR reliability risks. *The continuing risks that the increasing penetration of IBRs pose to the reliable operation of the Bulk-Power System underscore the need for mandatory Reliability Standards to address these issues on a nationwide basis.*" (Emphasis added.) Order 901, P24.

When BAL-002-WECC-3 is retired and replaced with NERC BAL-002-3, the amount and type of reserves required to be held back within the Western Interconnection will decrease. That frees those resources to be plied against load. Within the Western Interconnection, a vast majority of these sequestered resources are immediately dispatchable (such as hydro), thus serving as the perfect resource to match the less predictable response of variable generation.

[27] FERC Order 901, P11-15, 185 FERC ¶ 61,042, United States of America, Federal Energy Regulatory Commission (FERC), 18 CFR Part 40, Docket No. RM22-12-000; Reliability Standards to Address Inverter-Based Resources, October 19, 2023. Hereafter: Order 901
[28] Order 901, P24.

By making these dispatchable resources more operationally available, the secondary benefits may be to bolster the supply of generation to the market. This potential secondary benefit directly addresses vital public interests.[29]

### Dispatchable Resources Contribute Significantly to Essential Reliability Services (ERS) [30]

ERSs consist of frequency control, ramping capability, and voltage control.

Frequency control is necessary because the electric grid is designed to operate at a frequency of 60 hertz (Hz). Deviations from 60 Hz can have destructive effects on generators, motors, and equipment of all sizes and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. This requires an instantaneous (inertial) response from some resources and a fast response from other resources to slow the rate of fall during the arresting period, a fast increase in power output during the rebound period to stabilize the frequency, and a more prolonged contribution of additional power to compensate for lost resources and bring system frequency back to the normal level. Two NERC Reliability Standards address this:

- BAL-002-3 Disturbance Control Standard—Contingency Reserve from a Balancing Contingency Event
- BAL-003-2 Frequency Response and Frequency Bias Setting

Adequate ramping capability (the ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator's ability to adjust resource output can impact the ability of the operator to keep the system in balance. NERC Reliability Standard BAL-001-2 (Real Power Balancing Control Performance) addresses this issue.

Voltage must be controlled to protect system reliability and move power where it is needed in both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels. Several NERC Reliability Standards address voltage control.

Restated, replacing BAL-002-WECC-3 with NERC BAL-002-3 frees dispatchable resources to address FERC-identified reliability gaps created by variable generation, and may bolster vital public interests.

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[29] "335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social, and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard. " (Emphasis added.) Order 693, P35.

[30] "Essential Reliability Services (ERS) are the elemental 'reliability building blocks' from resources (generation and demand) necessary to maintain Bulk Power System (BPS) reliability." NERC ERS Task Force – Scope – 2014.

Because adequate levels of reserves are established in NERC BAL-002-3, and supported by BAL-003-2, BAL-002-WECC-3, Requirements R1 through R4 are not needed.

### Replacing BAL-002-WECC-3 With NERC BAL-002-3 Provides Sufficient Reserves at a Continent-Wide Level

In the earliest stages of the Western Interconnection's strides to establish adequate Contingency Reserves, the applicable entity's reserves were established by BAL-STD-002-0, Operating Reserves, at 5% of hydro generation and 7% thermal generation (50% spinning and 50% non-spinning).[31] These thresholds were not technically supported; they were the result of contractual negotiations. Today, such a standard would likely not be approved by FERC as violative of the principles established in FERC Order 672. (See foot note 2.)

As BAL-STD-0-2 was replaced with later iterations of that standard, the result was today's BAL-002-WECC-3, in which the Responsible Entity's reserves are set at:

R1.1.1 "The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;[32] (or)
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Bullet one of BAL-002-WECC-3 describes the Most Severe Single Contingency, or MSSC.

The MSSC ensures that all entities can recover Area Control Error (ACE) within 15 minutes. The MSSC serves as the upper Contingency Reserve threshold for all interconnections, except the Western Interconnection. Within the Western Interconnection, the levels of reserve set by BAL-002-WECC-3 can exceed that of the rest of the continent that is protected by FERC-approved BAL-002-3. As a result, the Western Interconnection carries an excess of reserve that exacerbates concerns raised by FERC in Order 901 wherein FERC addresses the need for continent-wide standards to backstop the operational performance of variable generation. Comparing NERC BAL-002-3 with BAL-002-WECC-3 illustrates this outcome.

NERC BAL-002-3 states that the BA and the RSG are not subject to compliance with BAL-002-3, R1 for multiple events that exceed the MSSC. NERC BAL-002-3 requires the applicable entity to deploy Contingency Reserve *up to its MSSC*; however, it does not require Contingency Reserve deployment *beyond MSSC.*

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[31] See Attachment - Transition from 5-7 to 3-3, as described in 2005 by Merrill Schultz; see also Attachment - History of WECC Reserve 5-7 Spin Merrill Schultz, March 3, 2005; see also BAL-STD-002-0, Operating Reserves.
[32] Also known as the Most Severe Single Contingency (MSSC).

By contrast, BAL-002-WECC-3 requires the applicable entity to maintain a level of Contingency Reserves *exceeding that required under NERC BAL-002-3*, as approved by FERC. Specifically, BAL-002-WECC-3, Requirement R1 requires the applicable entity to carry reserves that equal or exceed the entity's MSSC—beyond that required by BAL-002-3 that adequately serves the balance of the continent. Among other things, this means these valuable dispatchable resources in excess of the MSSC cannot be used to meet FERC's goal of backstopping variable resources as identified in FERC Order 901.

While the application of BAL-002-3 could free resources to enhance reliability, the application of BAL-002-WECC-3 can inhibit reliability when resources are withheld that could otherwise serve load and backstop variable resources.

For example:

Using historical data from January 2020 - May 2024, comparison of the hourly Contingency Reserve Requirement (calculated using 3% generation and 3% load) to the Most Severe Single Contingency (MSSC), the results identified there was more than 5,000 MW of capacity available during the summertime peak hours and between 2,000-2,500 MW during the remaining hours of the year. See figure below.

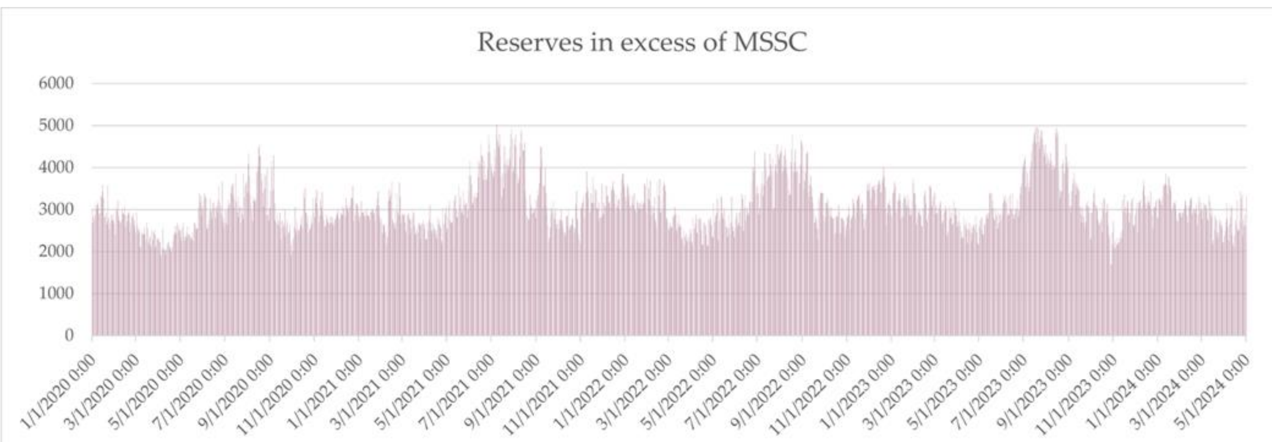


**Figure 1: Reserves in excess of MSSC**

### The Shortened Execution Time of BAL-002-WECC-3 Inhibits Reliability Due to Market Rules in the Western Interconnection

BAL-002-WECC-3, Requirements R3 and R4 require the applicable entity to restore Contingency Reserve within 60 minutes of the initiating event. By contrast, BAL-002-3 requires the applicable entity to achieve the same task in 105 minutes. As a result, BAL-002-WECC-3 requires the performance of the same task 45 minutes earlier than its continent-wide counterpart. This shortened period inhibits reliability in that it forces the applicable entities into transactions agreed upon during an arbitrarily shortened time window. Like BAL-002-3, Requirement R1., there is no technical support suggesting that rushing this transaction enhances reliability—yet it remains in force 28 years after its inception, still lacking any technical support.

Further, the restoration of reserves in a 60-minute timeframe is restrictive on the entity's ability to secure additional resources within the established business practices in the region. The NERC Standard of up to 105 minutes (90 minutes after the 15 minutes Contingency Recovery Period) after the event has less commercial impact and is acceptable from both a commercial standpoint as well as an operational standpoint.

The WECC requirement of 60 minutes from start of a DCS event restricts the deficient entity from rescheduling resources to replace those that were lost during the event. Western market practices require schedules to be submitted and approved well in advance to ensure reliability, and once the schedule windows close, it is difficult to make last-minute changes. Before markets, when transactions were bilateral, a recovery of generation resources was more flexible, and could be more quickly executed.

The NERC BAL-002-3 Contingency Reserve Restoration Period of up to 105 minutes allows applicable entities to use normal market scheduling practices to replace lost generation. FERC's approval of NERC BAL-002-3 shows its belief that the NERC standard of 105 minutes (90 plus 15) is adequate and does not degrade reliability.

In attempting to meet the 60-minute restoration requirement, the applicable entity has two options.

First, the BA must carry significantly more Contingency Reserve than is required to maintain an adequate level of reliability, or second, be prepared to enter an Energy Emergency Alert 3 which allows the BA to deploy Contingency Reserves to serve load. By definition, entering into an Energy Emergency Alert is an indication of reduced reliability. Given normal scheduling practices, a 90-minute restoration time allows a Responsible Entity to restore Contingency Reserve using normal established market scheduling practices.

In addition, many entities own BES equipment in more than one interconnection. Having a single standard enhances these entities' ability to stay in compliance with the standard using consistent business practices across the interconnections.

### Reserve Thresholds do Not Reflect Resource Mix

Due to the changing resource mix and the proliferation of renewable generation, battery storage, and retirements of conventional synchronous generation, resource adequacy has become a serious concern. The BAL-002-WECC standard unnecessarily ties up significant generation which is dispatchable, frequency responsive and fast ramping. Generation that could be used to meet ramps, follow variable resources, or simply meet expected loads, is committed to contingency reserve capacity that is not available to serve load. For example, Western Power Pool's Northwest Power Pool Reserve Sharing Group Northwest-Montana zone typically has a 1,200 MW MSSC, yet routinely has over 3,000 MW of reserves being held under the 3/3 requirement. That available capacity, usually in excess 1,800 MW, could be used to meet other reliability related services obligations. The existing 3/3 contingency reserve requirement results in the construction of at least 1800 MW of excess generation in the Northwest-Montana zone. The ability to use this generation capacity exceeding the MSSC will also allow entities to efficiently operate their facilities. Idled excess capacity will be reduced and productive generation increased.

Under NERC standard NERC BAL-002-3, the Eastern, Texas and Quebec Interconnections operate without the additional reserve requirement (3% load and 3% generation), and they are allowed to restore their reserves within 90 minutes. The changing market structure in the Western Interconnection has made it difficult to fully restore the required reserves within 60 minutes due to market scheduling timelines. This can lead to implementation of emergency procedures, typically Energy Emergency Alert 3 conditions, due to an energy shortfall precipitated by the 60-minute recovery period. When the Western markets were mostly bilateral, the 60-minute recovery was consistent with energy scheduling protocols. Market integration has altered energy scheduling protocols making it very difficult to modify schedules within 60 minutes of a generation contingency. For these reasons BAL-002-WECC-3 has become obsolete, while not enhancing reliability.

Reserves are unused or unloaded generation that are in a state of readiness in case there is sudden loss of loaded generation. When reserves are held above the MSSC, as they are in the Western Interconnection, excess capacity must be built that has no other reliability benefit. Every energy customer in the West absorbs this excess cost. Retirement of BAL-002-WECC-3 reallocates these excess resources to the benefit of the interconnection in the form of dispatchable, responsive, and available resources to reliably integrate future variable resources, such as wind, solar, and other renewable resources.

## Vital Public Interests will be Enhanced[33] [34]

### Market Timing Issues

The emergence of organized markets in WECC, since the inception of BAL-002-WECC-1 has brought a new dynamic in the timing and means by which the reserves are procured. The number of participants in the California ISO Energy Imbalance Market (AKA: Western Energy Imbalance Market, or WEIM)

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[33] "Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social, and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard." FERC Order No. 672 at P 335.

[34] "The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently." FERC Order No. 672 at P 328.

has grown significantly in the past several years. CAISO EIM market rules require a participating BA to balance its resources and loads 75 minutes before the next operating hour (T-75). Failure to do this can result in financial penalties to the participating BA. This rule has had the effect of discouraging any bilateral energy trading after T-75 and does not align well with a 60-minute reserve recovery time limit. No bilateral trading for replacement energy reserve is possible for the next operational hour because participating WEIM BAs cannot participate in trades within T-75.

This leaves the contingent BA in a resource short position when the 60-minute contingency restoration time expires. At this point, the contingent BA must activate emergency operating procedures up to asking the Reliability Coordinator to declare an EEA3, including load shedding to balance the contingent BA. By extending the contingency restoration time to 105 minutes (15-minute recovery plus 90-minute restoration), the contingent BA has at least 30 minutes to arrange replacement energy in a bilateral manner from other BAs or schedule their own resource in the WEIM. The additional contingency reserve recovery time allows the contingent BA to make orderly and planned adjustments and continue to serve firm load without the implementation of emergency operating procedures, up to and including shedding firm load.

FERC and the industry have determined that 90 minutes from the end of the recovery period (up to 15 minutes) is sufficient to maintain an adequate level of reliability. The shorter restoration period in the WECC creates artificial reliability issues as the applicable entity tries to rebalance supply and demand in an arbitrarily shorter period than that required in the NERC BAL-002-3.

To give a clear understanding of the impact of either option, the following example is provided.

Assume the NWPP RSG's MSSC is approximately 1,200 MW. Under BAL-002-WECC-3, the NWPP RSG would normally carry approximately 2,200-4,000 MW of Contingency Reserves depending on the time of year. Assuming the MSSC occurs, the NWPP RSG would activate 1,200 MW of its reserves and restore the ACE to the pre-event level. Members now have approximately 60 minutes to restore 1,200 MW of reserves while still carrying more than 1,000–2,800 MW, which is greater than the MSSC, assuming it was not reduced with the loss of the 1,180 MW event. See figure below.

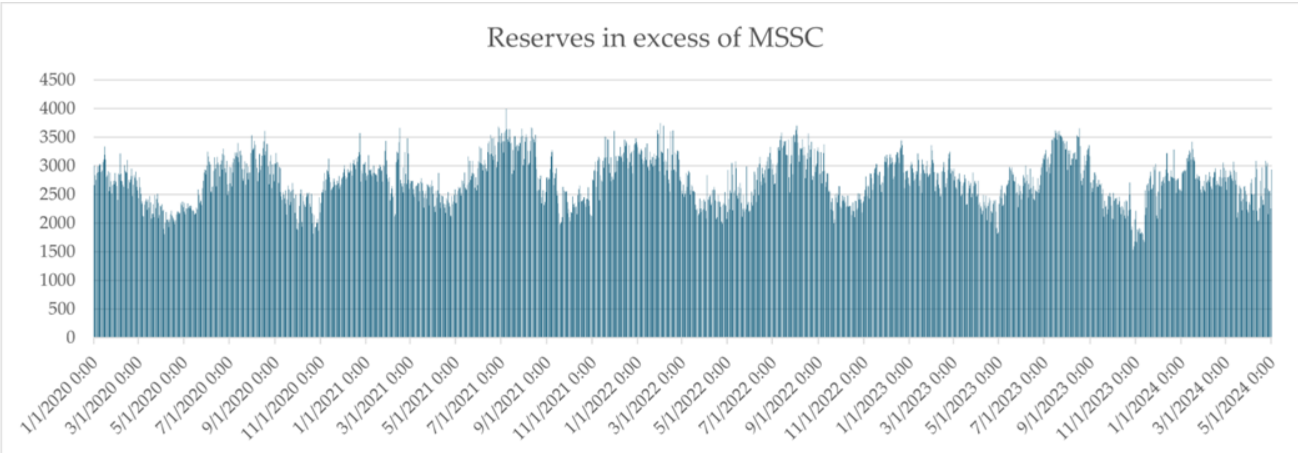


**Figure 2: Reserves in excess of MSSC; January 1, 2020, through May 1, 2024**

As discussed earlier, due to market rules related to the WEIM in which most entities are taking part, new resources cannot be added to an entity's reserves for the next hour (minimum time to add a resource under the WEIM (75 minutes), or other emerging markets. If a resource is not already in the WEIM, it cannot count toward the reserves needed. So, an entity must have already been carrying reserves greater than required under the WECC standard, or it must reduce load to balance its resources and loads including reserves. (It can be argued that by reducing loads, you are putting the interconnection at greater risk because you have removed one available resource, the load, from being an option for the next event.) To avoid the declaration of an EEA, the NWPP would need to carry an additional 1,000 MW above the required reserves or declare an EEA any time the reserves need to be restored within 60 minutes of the event.

When entities withhold extra reserves to avoid the EEA, this paradigm keeps 2,500 to 4,000 MW from serving load due to the WECC current standard, which has no technical merit, as compared to the NERC Standard. These additional resources could be used to help integrate more inverter-based resources and serve loads more efficiently if it were available for load service.

Entering an Energy Emergency Alert indicates reduced reliability. Given normal scheduling practices, which require bilateral schedules to be completed and approved 75 minutes before the hour, a 60-minute restoration time does not allow adequate time for a Responsible Entity to restore Contingency Reserve in less than 60 minutes from the initiating event, potentially resulting in an Energy Emergency Alert situation.

## Capacity Could be Better Used than Simply Holding Reserve

FERC and the industry have determined that the amount of Contingency Reserve needed to maintain an adequate level of reliability is the amount of Contingency Reserve needed to replace the MSSC resource. Holding Contingency Reserve more than MSSC precludes using operating reserve for other purposes, particularly load and resource balancing in real-time. As the grid transitions from conventional synchronous generation to more variable renewable resources, increasing capacity will be needed to manage the variability and faster ramping requirement of these resources. Allocating reserves in excess of that needed to maintain an adequate level of reliability, or MSSC, ultimately detracts from reliability.

## Conclusion

Retirement of BAL-002-WECC-3 Contingency Reserve would reduce required reserves in WECC without diminishing the ability to meet the deployment requirement. Freeing up reserves from the Contingency Reserve requirement would increase the resources available to manage variable resources and accommodate increased renewable resource integration.

The existing BAL-002-WECC-3 Contingency Reserve sets a BA's or RSG's Contingency Reserve requirement to the greater of the MSSC or 3% of the applicable entity's generation and 3% of its load. This 3/3 requirement exceeds MSSC for most responsible entities.

By contrast, NERC Standard BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event, Requirement R1.3.2 states that the BA/RSG is not subject to compliance with Requirement R1 for multiple events that exceed the MSSC. NERC BAL-002-3 requires the applicable entity to deploy Contingency Reserve up to the MSSC but does not require Contingency Reserve deployment beyond the MSSC.

In BAL-002-3, FERC and the industry have determined that the amount of Contingency Reserve needed to maintain an adequate level of reliability is the amount of Contingency Reserve needed to replace the MSSC resource.

Holding Contingency Reserve more than MSSC precludes using operating reserve for other purposes, particularly load and resource balancing in real time. As the grid transitions from conventional synchronous generation to more variable renewable resources, increasing capacity will be needed to manage the variability and faster ramping requirement of these resources. Allocating reserve in excess of that needed to maintain an adequate level of reliability, or MSSC, ultimately detracts from reliability.

BAL-002-WECC-3 requires an applicable entity to restore Contingency Reserve within 60 minutes of the initiating event (as opposed to up to 105 minutes in BAL-002-3), or 45 minutes sooner than required by BAL-002-3. With respect to impacts to the time to restore Contingency Reserve, FERC and the industry have determined that 90 minutes from the end of the recovery period (up to 15 minutes) is sufficient to maintain an adequate level of reliability. By contrast, the 60-minute requirement within BAL-002-WECC-3 creates potential reliability issues as an applicable entity tries to rebalance in an arbitrarily shorter period than that required in the NERC BAL-002-3. In attempting to meet the 60-minute restoration requirement, an applicable entity has two options. First, the BA must carry significantly more Contingency Reserve than is required to maintain an adequate level of reliability, or second, be prepared to enter an Energy Emergency Alert 3 and deploy Contingency Reserve to serve load. Given normal scheduling practices, a 90-minute restoration time allows an applicable entity to restore Contingency Reserve without employing emergency procedures.

Retirement of BAL-002-WECC-3 will enhance the reliable operation of the Western Interconnection by allowing resources that are presently used for overprotecting above the MSSC to be available to meet the immediate balancing needs of the Interconnection. This will free those resources to be used as needed in a rapidly changing system to maintain overall reliability.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-26-21 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-152:
WECC Risk Factor Criteria

| WECC Risk Factor Criteria for Inherent Risk Assessment<br>Effective March 22, 2021 | | | | |
|---|---|---|---|---|
| | Criteria for Assessment | | | |
| **Risk Factor** | **N/A** | **Low Risk** | **Medium Risk** | **High Risk** |
| **CIP - Impact Rating Criteria** | Entity has no BES Cyber Systems (BCS) | Entity has one or more low impact BCS(s) | Entity has one or more medium impact BCS(s) | Entity has one or more high impact BCS(s) |
| **ICCP Connectivity** | Entity has no BES Cyber Systems (BCS) | Entity has low impact BCS(s) without ICCP connections or external routable connectivity | Entity has low impact BCS(s) with at least one ICCP connection<br>- or -<br>Entity has low impact BCS(s) with external routable connectivity (LERC)<br>- or -<br>Entity has medium impact BCSs | Entity has medium impact BCS(s) with at least one ICCP connection<br>- or -<br>Entity has high impact BCS(s) |
| **Load** | Entity does not have any system load | Entity's system load is less than 300 MW | Entity's system load is between 300 - 2,000 MW | Entity's system load is greater than 2,000 MW |
| **Transmission Portfolio** | Entity does not own, operate, coordinate, plan, design, or monitor the status of transmission facilities | Entity has transmission facilities less than 200kV | Entity has transmission facilities between 200 - 300 kV<br>- or -<br>Entity has over 1,000 miles of transmission lines 100 kV or greater | Entity has transmission facilities greater than 300 kV<br>- or -<br>Entity has over 4,000 miles of transmission lines 200 kV or greater |
| **Critical Transmission** | Entity does not own, operate, coordinate, plan, design, or monitor the status of transmission facilities | Entity's system is not critical to adjacent entities as it is not being used as a flow through system for power flow | Entity's system is critical to adjacent entities as it is being used as a flow through system for power flow | Entity's system includes elements (owned or operated) of an IROL / Flowgate / Major Transmission Path (WECC) / Generic Transmission Limit (Texas RE) / Cranking Path |
| **Voltage Control** | Entity does not own or operate any voltage control equipment | ---------- | Entity owns and/or operates reactive resources to provide voltage control | Entity owns and/or operates reactive resources other than generators to provide voltage control |
| **Largest Generator Facility** | Entity does not own any generation facilities | Entity's largest single generation facility is less than 500 MVA | Entity's largest single generation facility is between 500 - 1,000 MVA | Entity's largest single generation facility is greater than 1,000 MVA |

| | | | | |
|---|---|---|---|---|
| **Total Generation Capacity** | Entity does not own or operate any generation facilities | Entity's total generation nameplate capacity is less than 1,000 MVA | Entity's total generation nameplate capacity is between 1,000 - 5,000 MVA | Entity's total generation nameplate capacity is greater than 5,000 MVA |
| **Variable Generation** | Entity does not meet any of the identified criteria | Less than 10% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation | 10% - 25% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation | Over 25% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation |
| **Balancing Authority (BA) Coordination** | Entity does not meet any of the identified criteria | Entity's BA Area has less than 5,000 MW of generation capacity | Entity's BA Area has between 5,000 - 10,000 MW of generation capacity | Entity's BA Area has greater than 10,000 MW of generation capacity<br>- or -<br>Entity's BA Area has greater than 5,000 MW of generation capacity and its Generation to Peak Load ratio is more than 1.2 |
| **Planned Facilities** | Entity does not meet any of the identified criteria | Entity is planning on or currently building transmission facilities less than 200 kV in the next three years<br>- or -<br>Entity is planning on or currently building generation facilities that are less than 500 MVA in the next three years | Entity is planning on or currently building transmission facilities between 200 - 300 kV in the next three years<br>- or -<br>Entity is planning on or currently building generation facilities that are between 500 and 1,000 MVA in the next three years | Entity is planning on or currently building transmission facilities greater than 300 kV in the next three years<br>- or -<br>Entity is planning on or currently building generation facilities greater than 1,000 MVA in the next three years |
| **RAS/SPS** | Entity does not own, operate, coordinate, plan, design, or monitor the status of a RAS/SPS | ---------- | Entity owns or designed a RAS/SPS that is not needed to meet TPL requirements<br>- or -<br>Entity owns or operates equipment that is part of a RAS/SPS that is not needed to meet TPL requirements | Entity owns or designed a RAS/SPS that is needed to meet TPL requirements<br>- or -<br>Entity owns or operates equipment that is part of a RAS/SPS that is needed to meet TPL requirements |

| | | | | |
|---|---|---|---|---|
| **Workforce Capability** | Entity does not meet any of the identified criteria | Less than 25% of the entity's System Operators have less than 5 years of System Operator experience | Between 25 - 50% of the entity's System Operators have less than 5 years of System Operator experience | Greater than 50% of the entity's System Operators have less than 5 years of System Operator experience |
| **System Restoration** | Entity has no responsibilities during system restoration | Entity has regional or company system restoration responsibilities limited to load restoration | Entity has Blackstart Resource(s)<br>- or -<br>Entity provides switching or other logistics based on the direction from a different entity responsible for the restoration plan | Entity is an RC<br>- or -<br>Entity is responsible for independent actions coordinated with an RC |
| **UFLS Equipment** | Entity does not own or operate UFLS equipment | Entity is responsible for 0% up to 0.3% of the entire regionally identified UFLS program | Entity is responsible for 0.3% to 1.3% of the entire regionally identified UFLS program | Entity is responsible for more than 1.3% of the entire regionally identified UFLS program |
| **UFLS Development and Coordination** | Entity is not responsible for developing or coordinating a UFLS program | Entity is responsible for developing and/or coordinating a UFLS program for less than 500 MW of load | Entity is responsible for developing and/or coordinating a UFLS program for 500 MW to 900 MW of load | Entity is responsible for developing and/or coordinating a UFLS program for 900 MW of load |
| **UVLS** | Entity does not have any UVLS responsibilities | The Registered Entity owns or operates UVLS that is less than 10% of its peak load | The Registered Entity owns or operates UVLS that is greater than or equal to 10%, but less than 25%, of its peak load | The Registered Entity owns or operates UVLS that is greater than or equal to 25% of its peak load |

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-26-24 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-153:
WECC Reliability Assessment Webpage

LOGIN

WECC

# Reliability Assessments

WECC's work identifies potential reliability risks to the Bulk Power System stemming from changes in loads and resources over the next 10 years. Through initiatives like the Western Assessment of Resource Adequacy, WECC provides analysis and information on resource adequacy to stakeholders and decision makers. WECC's work supports resource adequacy work at an ERO level by providing information on the West to assessments such as NERC's Long-Term Reliability Assessment (LTRA), Summer Assessment, Winter Assessment, and Probabilistic Assessment.

Request Outreach Event

Western Assessment

Western Assessment Comment Form

Resources

NERC Assessments

WECC Studies

Archive

# Reliability Assessments

- Interregional Transfer Capability Study

Calendar Contacts

Careers

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-26-21 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-159:
Email Correspondence with E3

| | |
|---|---|
| **From:** | Brad Cebulko |
| **To:** | Arne Olson; Fred Heutte |
| **Cc:** | Laura Burford; Michael Lenoff; Erik Olson; Edward Burgess |
| **Subject:** | Re: E3 NW RA study and Centralia |
| **Date:** | Friday, January 9, 2026 6:57:25 PM |

**External Sender**

Thank you, Arne.

______

**Brad Cebulko**
m: 317.519.3165

---

**From:** Arne Olson <arne@ethree.com>
**Sent:** Friday, January 9, 2026 3:43 PM
**To:** Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
**Cc:** Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
**Subject:** Re: E3 NW RA study and Centralia

Yes everything that I didn't comment on is correct

Sent from my Verizon, Samsung Galaxy smartphone
Get Outlook for Android

---

**From:** Brad Cebulko <bcebulko@currentenergy.group>
**Sent:** Friday, January 9, 2026 3:35:46 PM
**To:** Arne Olson <arne@ethree.com>; Fred Heutte <fred@nwenergy.org>
**Cc:** Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
**Subject:** Re: E3 NW RA study and Centralia

Arne,

I really appreciate the response as well as the data. Thank you. I have one final point of clarification. I understand your response as confirming the accuracy of our summary, subject to the qualifications and information you provided. Please let me know if that understanding is incorrect.

Have a great weekend.

______

**Brad Cebulko**
m: 317.519.3165

---

**From:** Arne Olson <arne@ethree.com>

**Sent:** Thursday, January 8, 2026 7:26 PM
**To:** Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
**Cc:** Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
**Subject:** RE: E3 NW RA study and Centralia

Hi Brad,

Thanks for this summary. I have placed some answers below in red. Also please see the attached spreadsheet with the data that was requested.

Please let me know if I can answer any other questions for you.

Best,

Arne

---

**From:** Brad Cebulko <bcebulko@currentenergy.group>
**Sent:** Friday, January 2, 2026 12:22 PM
**To:** Arne Olson <arne@ethree.com>; Fred Heutte <fred@nwenergy.org>
**Cc:** Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
**Subject:** Re: E3 NW RA study and Centralia

Arne,

Thank you again for speaking with us on Wednesday, December 31. We appreciate you taking the time to discuss your September 2025 presentation on resource adequacy to the Washington Utilities and Transportation Commission and the Washington Department of Commerce. We also appreciate your efforts to locate and share information on Canadian entitlements, the list of in-development resources, and achieved LOLE values. Thank you for your assistance. My understanding is that your anticipated timing works, as the deadline for making use of the materials would be early the following week.

To confirm the accuracy of our notes from the Wednesday call, my colleagues and I have summarized our understanding below. Would you please let us know if the notes below are accurate and if any modifications to the below are appropriate? If possible, we'd be happy to receive this response in advance of the other materials, but also understand your schedule may get in the way.

- The "Greater Northwest" region evaluated in the presentation includes all of the traditional NW Power Act Northwest (Washington, Oregon, Idaho and western Montana) plus all of NorthWestern Energy and PAC-East.
- Slide 10 of the presentation is based on the following inputs:

- Each year shown in the table is a water year beginning October 1. So, for instance, "2026" refers to the year from October 1, 2025 through September 30, 2026.

- The "peak load" used to calculate "Total Resource Need" was developed by E3's own load forecast. To forecast data center demand, including whether data centers will reduce load at times of peak demand, E3 used figures from utilities' integrated resource plans.

- The "planning reserve margin" used to calculate "Total Resource Need" was calculated to achieve a loss of load expectation of one event-day per decade (i.e., the 1-in-10 LOLE standard). E3 used its own loss-of-load expectation model to calculate the planning reserve margin.

- The "Existing Portfolio w/ Retirements" assigns value to individual resources based on E3's own set of capacity accreditation values that were developed using E3's calculations of resource types' marginal effective load carrying capacity.

- E3's August whitepaper explains E3's accreditation approach.

- Centralia is modeled as retired for all study years. In other words, the study attributes 0 MW to Centralia and does not model the proposed coal-to-gas conversion of Centralia scheduled to be completed in 2028.

- The "firm imports" of 3,750 MW each year is calculated by looking to the 2,500 MW figure that the Northwest Power and Conservation Council uses for a smaller region than the region E3 studies for the presentation. E3 added to the 2,500 MW figure to account for the larger region. E3 was intentionally conservative in setting the 3,750 MW figure. The 3,750 MW figure is not intended to represent the maximum import capability of the region E3 studied.

- The quantum of "in-development" Firm, Wind, Solar, and Battery resources are sourced from WECC's Anchor Data Set, after accreditation using E3's calculations of resource types' effective load carrying capacity. The quantum of "in-development" resources does not include planned resources in utilities' integrated resource plans shown on slide 21. To confirm whether the "in-development" resources are in service, one can investigate the status of resources shown in the WECC Anchor Data Set, including by reference to press releases.

- With regard to the "Reliability Positions" shown on slide 10:
    - The "Surplus" or "Shortfall" does not include the "in-development" resources. So, for instance, including the "in-development" resources for 2026 improves the calculated Reliability Position from a shortfall of 1,321 MW to a shortfall of 380 MW.

  - Any electric system will have some level of resource adequacy risk. The “Surplus” or “Shortfall” shows whether the region has more or fewer resources needed to achieve, in E3’s model, the target risk threshold of a loss of load expectation of one event-day in ten years. A shortfall indicates that the region has higher risk of loss of load than the one event-day in ten years standard. A surplus indicates that the region has lower risk of loss of load than the one event-day in ten years standard.
  - The “Surplus” or “Shortfall” does not show whether the region has insufficient resources to meet forecasted peak load.

THE ‘SURPLUS’ OR ‘SHORTFALL’ SHOWS WHETHER THE REGION HAS SUFFICIENT RESOURES TO MEET FORECASTED PEAK LOAD PLUS THE PLANNING RESERVE MARGIN NEEDED TO ACHIEVE THE 0.1 LOLE RESOURCE ADEQUACY STANDARD.

  - For 2026, the risk in the studied region is slightly elevated above the target risk.
  - The planned resources in utilities’ integrated resource plans shown on slide 21 are enough to meet the shortfalls shown on slide 10 for all years studied.
  - Data center flexibility, such as reductions in demand during times of peak demand, can help address the calculated shortfalls.

- Slide 12 indicates that there is essentially no LOLE risk in the year 2025 unless there is a “bad” water year. Will you please clarify whether Slide 12 represents water year 2025 (October 1, 2024 – September 30, 2025)?

CORRECT

- The study finds that the greatest risk to the system is during low hydro years and the evidence, as of December 31, 2025, does not indicate we are in a low hydro year.

- With regard to the presentation’s fit to current conditions:
  - The presentation is based on a probabilistic model incorporating 30 years of past weather and hydrological conditions. The model does not reflect actual weather and hydrological conditions presently existing for this winter, such as La Niña. Similarly, the model does not reflect weather and hydrological forecasts for this winter.

THE MODEL CONSIDERS 30 HYDRO YEARS (1989-2018) AND 44 TEMPERATURE YEARS (1979-2022). THE HYDRO YEARS AND LOAD YEARS ARE PAIRED RANDOMLY USING MONTE CARLO DRAWS.

  - To gauge the extent to which the model represents current conditions, the key factors are: (1) weather forecasts; (2) hydrological conditions; (3) load conditions; and (4) resource additions and retirements. Thus, for instance, if prevailing and forecasted hydrological conditions are stronger than the average conditions observed in the 30-year dataset used for the model, and holding constant other factors, the “Reliability Position” shown on slide 10 likely underestimates the actual reliability position in the region. The same goes for a winter weather forecast that is milder than the average weather observed over the thirty-year dataset used for the model.

  - Flexibility of data center demand, such as reductions in demand during times of peak load, is one way to help address the shortfalls shown on slide 10.

CORRECT, HOWEVER, DATA CENTER "LOAD FLEXIBILITY" IS OFTEN ACHIEVED WITH ONSITE GENERATION. THIS WOULD MOVE THE PROBLEM FROM ONE SIDE OF THE METER TO THE OTHER, BUT WOULDN'T ELIMINATE THE NEED TO BUILD THE RESOURCES SUBJECT TO THE SUPPLY CHAIN AND OTHER CHALLENGES. TRUE FLEXIBILITY OF COMPUTE LOAD WOULD BE A SIGNIFICANT NEW RESOURCE BUT WE HAVE NOT YET SEEN EVIDENCE OF THIS AT SCALE.

- The Department of Energy's December 16, 2025 Order No. 202-25-11 to Transalta is counterproductive and risks harming reliability in the studied region to the extent the order delays the conversion of Centralia Unit 2 to gas. The order need not be renewed in March 2026 to address the Reliability Positions shown on slide 10 of the presentation.

Please let me know if you have any clarifying questions. Thank you again, and Happy New Year.

**Brad Cebulko**
m: 317.519.3165

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**From:** Arne Olson <arne@ethree.com>
**Sent:** Wednesday, December 31, 2025 6:32 PM
**To:** Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
**Cc:** Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>
**Subject:** RE: E3 NW RA study and Centralia

Hi all, thanks for the good questions this morning. Just following up to let you know that, given the holidays and some upcoming deadlines, we will aim to get you the information you requested by late next week. The information we are digging up is:

- Details on how we are modeling the Canadian Entitlement
- List of the "in-development" resources through 2030
- Achieved LOLE values for each year through 2030

Let me know if there is any additional information you might need, and also if there is any impending deadline that we should be aware of.

Also, here is a link to E3's newest resource adequacy white paper.

https://www.ethree.com/new-framework-resource-adequacy/

As I mentioned during our call, it's intended to be a detailed guidebook for how to evaluate resource adequacy needs across markets and vertically integrated systems. Happy to answer any questions you might have about the white paper, or if any other questions come up about our current NW study.

Happy New Year!

Arne

-----Original Appointment-----
**From:** Arne Olson
**Sent:** Monday, December 29, 2025 2:08 PM
**To:** Arne Olson; Brad Cebulko; Fred Heutte
**Cc:** Laura Burford; Michael Lenoff; Erik Olson
**Subject:** E3 NW RA study and Centralia
**When:** Wednesday, December 31, 2025 8:00 AM-8:25 AM (UTC-08:00) Pacific Time (US & Canada).
**Where:** Microsoft Teams Meeting

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## Microsoft Teams Need help?

### Join the meeting now

Meeting ID: 256 665 160 678 92
Passcode: Ei7NT9X3

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For organizers: Meeting options

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-26-21 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-159a:
E3's Attachment to Email Correspondence with E3

## Columbia River Treaty Regime

Sources

https://www.state.gov/bureau-of-western-hemisphere-affairs/details-about-the-key-elements-agreed-between-the-united-states-and-canada-regarding-modernization-of-the-columbia-river-treaty-regime

*(Table 1.) https://www.congress.gov/crs-product/R43287*

| Year | Capacity (MW)1 | Generation (MW)2 |
|---|---|---|
| 2024 (Baseline) | 1,141 | 454 |
| 2025-2029 | 660 | 305 |
| 2030 | 590 | 278 |
| 2031 | 573 | 225 |
| 2032 | 565 | 225 |
| 2033 | 558 | 225 |
| 2034-2044 | 550 | 225 |

## How it is modeled

The capacity component of the treaty (1) was interpreted as the capacity BC is able to access and demand at any point in time. After consulting with BPA, we also interpret that BC could demand this amount for a sustained long period of time, such as for two weeks or more, without violating the generation amounts of the treaty (2) which is itself interpreted as the annual average energy for the treaty. This means the treaty's capacity could be requested for longer than the reliability risk periods and present a firm requirement. **Therefore, the capacity component of the treaty was modeled as a firm obligation which increases the region's total reliability need by the same amount in MWs.**

| Year | Firm Obligation, MW |
|---|---|
| 2025 | 660 |
| 2026 | 660 |
| 2027 | 660 |
| 2028 | 660 |
| 2029 | 660 |
| 2030 | 590 |

## In-Development Resources

Sources
https://www.wecc.org/program-areas/reliability-planning-performance-analysis/reliability-modeling/anchor-data-set-ads
https://www.pacificorp.com/energy/integrated-resource-plan.html

Plant-level list in-development resources within the Greater Northwest Study Region with commission dates between 2025-2030. In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and can be verified online. In-development resources include coal-to-gas plant conversions in Pacificorp's 2025 IRP. Plants with commission dates before January 1 are considered available in the study year. Each resource is assgined to a Transmission Zone based on physical location within the Greater Northwest for zonal modeling.

| Annual Capacity Additions (Nameplate MW) | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
|---|---|---|---|---|---|---|---|
| Hydro | 99 | 251 | 78 | 2 | 91 | - | 522 |
| Nuclear | - | - | - | - | - | - | - |
| Coal | - | - | - | - | - | - | - |
| Gas | 1,339 | 357 | - | - | 205 | 360 | 2,261 |
| Other | - | - | - | - | - | - | - |
| Wind | 1,026 | 1,126 | 460 | - | - | - | 2,611 |
| Solar | 344 | 1,396 | 125 | - | - | - | 1,866 |
| BTM Solar | - | - | - | - | - | - | - |
| Battery Storage | 460 | 545 | - | - | - | - | 1,005 |
| Demand Response | - | - | - | - | - | - | - |
| Total | 3,267 | 3,676 | 663 | 2 | 296 | 360 | 8,264 |

| Source | GeneratorKey | Name | State | County | Tranmission Zone | Rated Capacity (Nameplate MW) | Resource Type | Balancing Authority | Commission Date | First Available Year |
|---|---|---|---|---|---|---|---|---|---|---|
| ADS 2034 | 2177 | Meyers Falls 1 HY | WA | NA | PNW_NE | 1 | Hydro | AVA | 12/31/2024 | 2025 |
| ADS 2034 | 2197 | Upper Falls Post St 1 HY | WA | NA | PNW_NE | 10 | Hydro | AVA | 1/4/2026 | 2027 |
| ADS 2034 | 2393 | Cedar Falls 2 HY | WA | NA | PNW_NW | 15 | Hydro | PSEI | 1/1/2026 | 2027 |
| ADS 2034 | 2394 | Cedar Falls 1 HY | WA | NA | PNW_NW | 15 | Hydro | PSEI | 1/1/2026 | 2027 |
| ADS 2034 | 3472 | Thompson Falls 2 HY | MT | NA | Inland_NW | 5 | Hydro | NWMT | 6/1/2025 | 2026 |
| ADS 2034 | 3479 | Thompson Falls 6 HY | MT | NA | Inland_NW | 5 | Hydro | NWMT | 12/1/2024 | 2025 |
| ADS 2034 | 3480 | Thompson Falls 5 HY | MT | NA | Inland_NW | 5 | Hydro | NWMT | 12/1/2024 | 2025 |
| ADS 2034 | 3481 | Thompson Falls 4 HY | MT | NA | Inland_NW | 5 | Hydro | NWMT | 3/31/2025 | 2026 |
| ADS 2034 | 3486 | Holter 4 HY | MT | Lewis&Clark | Inland_NW | 10 | Hydro | NWMT | 6/15/2025 | 2026 |
| ADS 2034 | 3487 | Holter 3 HY | MT | Lewis&Clark | Inland_NW | 10 | Hydro | NWMT | 7/1/2025 | 2026 |
| ADS 2034 | 3488 | Holter 2 HY | MT | Lewis&Clark | Inland_NW | 10 | Hydro | NWMT | 8/25/2025 | 2026 |
| ADS 2034 | 3489 | Ryan 6 HY | MT | NA | Inland_NW | 8 | Hydro | NWMT | 1/1/2025 | 2026 |
| ADS 2034 | 3490 | Ryan 5 HY | MT | NA | Inland_NW | 8 | Hydro | NWMT | 3/9/2025 | 2026 |
| ADS 2034 | 3515 | Ryan 3 HY | MT | NA | Inland_NW | 8 | Hydro | NWMT | 12/1/2024 | 2025 |
| ADS 2034 | 3517 | Ryan 1 HY | MT | NA | Inland_NW | 8 | Hydro | NWMT | 12/1/2024 | 2025 |
| ADS 2034 | 3531 | Holter 1 HY | MT | Lewis&Clark | Inland_NW | 10 | Hydro | NWMT | 12/1/2025 | 2026 |
| ADS 2034 | 3537 | Thompson Falls 3 HY | MT | NA | Inland_NW | 5 | Hydro | NWMT | 4/1/2025 | 2026 |
| ADS 2034 | 3539 | Thompson Falls 1 HY | MT | NA | Inland_NW | 5 | Hydro | NWMT | 6/1/2025 | 2026 |
| ADS 2034 | 4925 | Boundary 1 HY | WA | NA | PNW_NW | 158 | Hydro | SCL | 8/1/2025 | 2026 |
| ADS 2034 | 4966 | Long_Lake_1 | WA | Lincoln | PNW_NE | 9 | Hydro | AVA | 12/31/2024 | 2025 |
| ADS 2034 | 7473 | Lagrande 2 HY | WA | NA | PNW_NW | 6 | Hydro | TPWR | 1/1/2024 | 2025 |
| ADS 2034 | 7474 | Lagrande 3 HY | WA | NA | PNW_NW | 6 | Hydro | TPWR | 1/1/2024 | 2025 |
| ADS 2034 | 7475 | Lagrande 4 HY | WA | NA | PNW_NW | 6 | Hydro | TPWR | 1/1/2024 | 2025 |
| ADS 2034 | 7606 | Long_Lake_2 | WA | Lincoln | PNW_NE | 9 | Hydro | AVA | 12/31/2024 | 2025 |
| ADS 2034 | 7607 | Long Lake 3 HY | WA | NA | PNW_NE | 18 | Hydro | AVA | 12/1/2025 | 2026 |
| ADS 2034 | 7608 | Long Lake 4 HY | WA | NA | PNW_NE | 18 | Hydro | AVA | 1/1/2028 | 2029 |
| ADS 2034 | 8613 | Ryan 2 HY | MT | Cascade | Inland_NW | 9 | Hydro | NWMT | 12/13/2024 | 2025 |
| ADS 2034 | 8614 | Ryan 4 HY | MT | Cascade | Inland_NW | 9 | Hydro | NWMT | 12/31/2024 | 2025 |
| ADS 2034 | 9698 | Gorge 1 HY | WA | NA | PNW_NW | 37 | Hydro | SCL | 1/1/2028 | 2029 |
| ADS 2034 | 9699 | Gorge 2 HY | WA | NA | PNW_NW | 37 | Hydro | SCL | 1/1/2028 | 2029 |
| ADS 2034 | 18045 | Boswell Springs Wind WT | WY | Sweetwater | Central_West | 320 | Wind | PACE | 4/1/2024 | 2025 |
| ADS 2034 | 18048 | Cedar Creek Wind WT | ID | Power | Central_West | 152 | Wind | PACE | 4/1/2024 | 2025 |
| ADS 2034 | 18179 | Hauser Agg HY | MT | Lewis&Clark | Inland_NW | 17 | Hydro | NWMT | 12/31/2024 | 2025 |
| ADS 2034 | 18210 | Uinta Agg HY | UT | Uintah | Central_West | 1 | Hydro | PACE | 12/1/2025 | 2026 |
| ADS 2034 | 18218 | Utility Solar+Storage - PV - S-O | OR | NA | PNW_SW | 1 | Battery Storage | PACW | 1/1/2024 | 2025 |
| ADS 2034 | 18224 | Big Fork 1 HY | MT | Flathead | PNW_NE | 2 | Hydro | BPAT | 1/1/2027 | 2028 |
| ADS 2034 | 18345 | Glen Canyon Solar A PV-T | UT | Kane | Central_West | 95 | Solar | PACE | 1/1/2024 | 2025 |
| ADS 2034 | 19147 | Tower Rd Solar PV-T | OR | Morrow | PNW_NE | 120 | Solar | BPAT | 12/1/2024 | 2026 |
| ADS 2034 | 19260 | Farmers Irrigation District Coppe | OR | Hood River | PNW_SW | 2 | Hydro | PACW | 1/1/2026 | 2027 |
| ADS 2034 | 20916 | Oregon Trail Solar PV-T | OR | Gilliam | PNW_NE | 41 | Solar | BPAT | 12/31/2025 | 2026 |
| ADS 2034 | 20917 | Green River Energy Center PV-T | UT | Emery | Central_West | 400 | Solar | PACE | 6/15/2025 | 2026 |
| ADS 2034 | 20962 | Cedar Springs Wind IV WT | WY | NA | Central_West | 350 | Wind | PACE | 12/31/2024 | 2025 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| ADS 2034 | 20963 | Anticline Wind WT | WY | NA | Central_West | 101 | Wind | PACE | 12/31/2024 | 2025 |
| ADS 2034 | 20964 | Two Rivers Wind LLCWT | WY | Carbon | Central_West | 280 | Wind | PACE | 3/31/2025 | 2026 |
| ADS 2034 | 21121 | Franklin BESS paired with Solar | ID | Twin Falls | Central_West | 60 | Battery Storage | IPCO | 6/1/2024 | 2025 |
| ADS 2034 | 21163 | Oregon Trail BESS BA | OR | Gilliam | PNW_NE | 41 | Battery Storage | BPAT | 12/31/2025 | 2026 |
| ADS 2034 | 21164 | Tower Rd BESS BA | OR | Morrow | PNW_NE | 60 | Battery Storage | BPAT | 12/31/2025 | 2026 |
| ADS 2034 | 21215 | Jim Bridger 1 ST | WY | Sweetwater | Central_West | 578 | Gas | PACE | 4/1/2024 | 2025 |
| ADS 2034 | 21216 | Jim Bridger 2 ST | WY | Sweetwater | Central_West | 586 | Gas | PACE | 4/1/2024 | 2025 |
| ADS 2034 | 21401 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21402 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21403 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21404 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21405 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21406 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21407 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21408 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21409 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21410 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21411 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21412 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21413 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21414 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21415 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21416 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21417 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21418 | Yellowstone County Generating | MT | Yellowstone | Inland_NW | 10 | Gas | NWMT | 5/15/2024 | 2025 |
| ADS 2034 | 21423 | DaveJohnston 1 1 ST | WY | Converse | Central_West | 99 | Gas | PACE | 1/1/2029 | 2029 |
| ADS 2034 | 21432 | Naughton 1 (natural gas convers | WY | Lincoln | Central_West | 156 | Gas | PACE | 1/1/2026 | 2026 |
| ADS 2034 | 21433 | Naughton 2 (natural gas convers | WY | Lincoln | Central_West | 201 | Gas | PACE | 1/1/2026 | 2026 |
| ADS 2034 | 21678 | Additional Hemingway Standalo | ID | Owyhee | Central_West | 36 | Battery Storage | IPCO | 6/1/2024 | 2025 |
| ADS 2034 | 21679 | Elmore Distributed BESS BA | ID | Elmore | Central_West | 3 | Battery Storage | IPCO | 6/1/2024 | 2025 |
| ADS 2034 | 21680 | Happy Valley BESS I 1 BA | ID | Canyon | Central_West | 39 | Battery Storage | IPCO | 6/1/2025 | 2026 |
| ADS 2034 | 21681 | Happy Valley BESS II 1 BA | ID | Canyon | Central_West | 39 | Battery Storage | IPCO | 6/1/2025 | 2026 |
| ADS 2034 | 21682 | Kuna BESS 1 BA | ID | Ada | Central_West | 150 | Battery Storage | IPCO | 6/1/2025 | 2026 |
| ADS 2034 | 21683 | Melba Distributed BESS BA | ID | Canyon | Central_West | 2 | Battery Storage | IPCO | 6/1/2024 | 2025 |
| ADS 2034 | 21735 | Parowan Solar BA | UT | Iron | Central_West | 58 | Battery Storage | PACE | 12/1/2024 | 2025 |
| ADS 2034 | 21749 | Pump Storage - West 1 PS | OR | Douglas | PNW_SW | 35 | Hydro | PACW | 1/1/2026 | 2027 |
| ADS 2034 | 21752 | Coffee Creek 1 BA | OR | Washington | PNW_NE | 17 | Battery Storage | BPAT | 6/1/2025 | 2026 |
| ADS 2034 | 21753 | Constable BESS 1 BA | OR | Washington | PNW_SW | 100 | Battery Storage | BPAT | 12/31/2024 | 2025 |
| ADS 2034 | 21754 | Seaside BESS 1 BA | OR | Multnomah | PNW_SW | 200 | Battery Storage | BPAT | 6/1/2025 | 2026 |
| ADS 2034 | 21755 | Troutdale BESS 1 BA | OR | Multnomah | PNW_NE | 200 | Battery Storage | BPAT | 12/31/2024 | 2025 |
| ADS 2034 | 22116 | Pleasant Valley Solar II 1 PV-T | ID | Ada | Central_West | 125 | Solar | IPCO | 12/1/2026 | 2027 |
| ADS 2034 | 22212 | Arco Wind WT | ID | Bonneville | Central_West | 360 | Wind | PACE | 12/1/2026 | 2027 |
| ADS 2034 | 22215 | Faraday Solar B LLC PV-T | UT | Utah | Central_West | 525 | Solar | PACE | 9/30/2025 | 2026 |
| ADS 2034 | 22217 | Hornshadow Solar II LLC PV-T | UT | Emery | Central_West | 200 | Solar | PACE | 6/30/2025 | 2026 |
| ADS 2034 | 22218 | Hornshadow Solar LLC PV-T | UT | Emery | Central_West | 100 | Solar | PACE | 6/30/2025 | 2026 |
| ADS 2034 | 22220 | Parowan Solar PV-T | UT | Iron | Central_West | 58 | Solar | PACE | 12/1/2024 | 2025 |
| ADS 2034 | 22231 | Rock Creek I Wind 32 WT | WY | Carbon | Central_West | 195 | Wind | PACE | 6/1/2025 | 2026 |
| ADS 2034 | 22232 | Rock Creek II Wind 66 WT | WY | Albany | Central_West | 403 | Wind | PACE | 9/1/2025 | 2026 |
| ADS 2034 | 22256 | Buckaroo Solar 1 PV-T | OR | Pendleton | PNW_SW | 2 | Solar | PACW | 9/30/2025 | 2026 |
| ADS 2034 | 22257 | Buckaroo Solar 2 PV-T | OR | Pendleton | PNW_SW | 3 | Solar | PACW | 9/30/2025 | 2026 |
| ADS 2034 | 22262 | Antelope Creek Solar LLC PV-T | OR | Jackson | PNW_SW | 2 | Solar | PACW | 4/19/2024 | 2025 |
| ADS 2034 | 22264 | Black Rock Solar PV-T | WA | Yakima | PNW_NE | 100 | Solar | BPAT | 1/1/2024 | 2025 |
| ADS 2034 | 22267 | Green Solar LLC PV-T | OR | Culver | PNW_SW | 3 | Solar | TH_Malin | 3/15/2024 | 2025 |
| ADS 2034 | 22268 | High Top Solar PV-T | WA | Yakima | PNW_NE | 80 | Solar | BPAT | 4/1/2024 | 2025 |
| ADS 2034 | 22270 | Orchard Knob Solar PV-T | OR | Polk | PNW_NE | 2 | Solar | BPAT | 2/23/2024 | 2025 |
| ADS 2034 | 22274 | Pilot Rock Solar I PV-T | OR | Umatilla | PNW_SW | 2 | Solar | PACW | 9/30/2025 | 2026 |
| ADS 2034 | 22275 | Pilot Rock Solar II PV-T | OR | Umatilla | PNW_SW | 3 | Solar | PACW | 9/30/2025 | 2026 |
| ADS 2034 | 22276 | Pine Grove Solar LLC PV-T | OR | Klamath | PNW_SW | 1 | Solar | TH_Malin | 2/16/2024 | 2025 |
| ADS 2034 | 22281 | Sunset Ridge Solar LLC PV | OR | Klamath | PNW_SW | 2 | Solar | TH_Malin | 7/25/2024 | 2025 |
| ADS 2034 | 22292 | Clearwater II 37 WT | MT | Custer | Central_West | 103 | Wind | PACE | 1/2/2024 | 2025 |
| ADS 2034 | 22323 | BHCE 100 MW Wind WT | CO | TBD | PNW_NE | 100 | Wind | BPAT | 1/1/2026 | 2027 |
| ADS 2034 | 22340 | Beaver Creek 1 WT | MT | Gallatin | Inland_NW | 248 | Wind | NWMT | 3/1/2025 | 2026 |
| ADS 2034 | 22487 | Sprague Hydro (North Fork) 1 H | OR | Klamath | PNW_SW | 1 | Hydro | PACW | 1/1/2024 | 2025 |
| ADS 2034 | 22546 | Wallowa Falls 1 HY | OR | NA | PNW_SW | 1 | Hydro | PACW | 1/1/2026 | 2027 |
| ADS 2034 | 22567 | DaveJohnston 2 2 ST | WY | Converse | Central_West | 106 | Gas | PACE | 1/1/2029 | 2029 |
| Pacificorp 2025 IRP | Pacificorp 2025 IRP | E3 Dave Johnston 4 Coal-to-Ga | WY | Converse | Central_West | 360 | Gas | PACE | 12/31/2029 | 2030 |

## Greater Northwest System Metrics

| | Unit | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|
| Total Resource Need* | *MW* | 49,245 | 50,737 | 52,499 | 54,184 | 55,879 | 57,195 |
| Existing Portfolio w/ Retirements** | *MW* | 46,716 | 45,666 | 45,395 | 45,388 | 45,098 | 44,757 |
| Firm Imports | *MW* | 3,750 | 3,750 | 3,750 | 3,750 | 3,750 | 3,750 |
| **Reliability Position** ***before Resource Additions*** Surplus (+) / Shortfall (-) | *MW* | 1,221 | -1,321 | -3,354 | -5,046 | -7,031 | -8,689 |
| "In-Development"*** Firm Resources | *MW* | 0 | 296 | 407 | 580 | 770 | 1,114 |
| "In-Development" Wind, Solar and Battery projects | *MW* | 0 | 645 | 1,015 | 1,316 | 1,508 | 1,934 |

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

***Does not include new gas capacity from converted coal units, only the coal retirements. New gas capacity from conversion categorized as "In-Development" below. Still includes retirement of Centralia 2, at 687 MW of effective firm capacity.*

*** In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and can be verified online. Includes new gas capacity from the conversion of coal units. Does not inclue repowering of Centralia 2 as a gas unit.*

| System Metrics including "In-Development" Resources | Unit | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|
| **Reliability Position** ***with "In-Development" Resources*** Surplus (+) / Shortfall (-) | *MW* | 1,221 | -380 | -1,932 | -3,150 | -4,753 | -5,641 |
| **Loss-of-Load Expectation** | *MWh/year* | 63 | 1,212 | 6,987 | 20,398 | 58,132 | 98,067 |
| | *Hours/year* | 0.14 | 1.65 | 5.58 | 14.70 | 36.43 | 56.57 |
| | *Days/year* | 0.01 | 0.15 | 0.68 | 1.77 | 4.14 | 6.01 |
| | *% chance/year* | 0.3% | 5.2% | 21.0% | 40.5% | 59.4% | 67.5% |

## Greater Northwest System Metrics

| | Unit | 2025 | 2026 |
|---|---|---|---|
| Total Resource Need* | *MW* | 49,245 | 50,737 |
| Existing Portfolio w/ Retirements** | *MW* | 46,716 | 45,666 |
| Firm Imports | *MW* | 3,750 | 3,750 |
| **Reliability Position** ***before Resource Additions*** Surplus (+) / Shortfall (-) | *MW* | 1,221 | -1,321 |
| “In-Development”*** Firm Resources | *MW* | 0 | 296 |
| “In-Development” Wind, Solar and Battery projects | *MW* | 0 | 645 |

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia*

***Does not include new gas capacity from converted coal units, only the coal retirements. New gas capacity fro*

*** In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and*

| System Metrics including "In-Development" Resources | Unit | 2025 | 2026 |
|---|---|---|---|
| **Reliability Position** ***with "In-Development" Resources*** Surplus (+) / Shortfall (-) | *MW* | 1,221 | -380 |
| **Loss-of-Load Expectation** | *MWh/year* | 63 | 1,212 |
| | *Hours/year* | 0.14 | 1.65 |
| | *Days/year* | 0.01 | 0.15 |
| | *% chance/year* | 0.3% | 5.2% |

| 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|
| 52,499 | 54,184 | 55,879 | 57,195 |
| 45,395 | 45,388 | 45,098 | 44,757 |
| 3,750 | 3,750 | 3,750 | 3,750 |
| -3,354 | -5,046 | -7,031 | -8,689 |
| 407 | 580 | 770 | 1,114 |
| 1,015 | 1,316 | 1,508 | 1,934 |

*ı River Treaty Regime*

*m conversion categorized as "In-Development" below. Still includes retirement of Centralia 2, at 687 MW of effective firr*

*can be verified online. Includes new gas capacity from the conversion of coal units. Does not inclue repowering of Centra*

| 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|
| -1,932 | -3,150 | -4,753 | -5,641 |
| 6,987 | 20,398 | 58,132 | 98,067 |
| 5.58 | 14.70 | 36.43 | 56.57 |
| 0.68 | 1.77 | 4.14 | 6.01 |
| 21.0% | 40.5% | 59.4% | 67.5% |

*ılia 2 as a gas unit*.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-26-21 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-160:
Clean Air Task Force Toll from Coal

# Craig

## Moffat, Colorado

**Owner** MidAmerican Energy Holdings Co, 12.9%, Salt River Project, 12%, Salt River Project, 19.3%, Tri-State G & T Assn Inc, 49.3%, Xcel Energy Inc, 6.5%

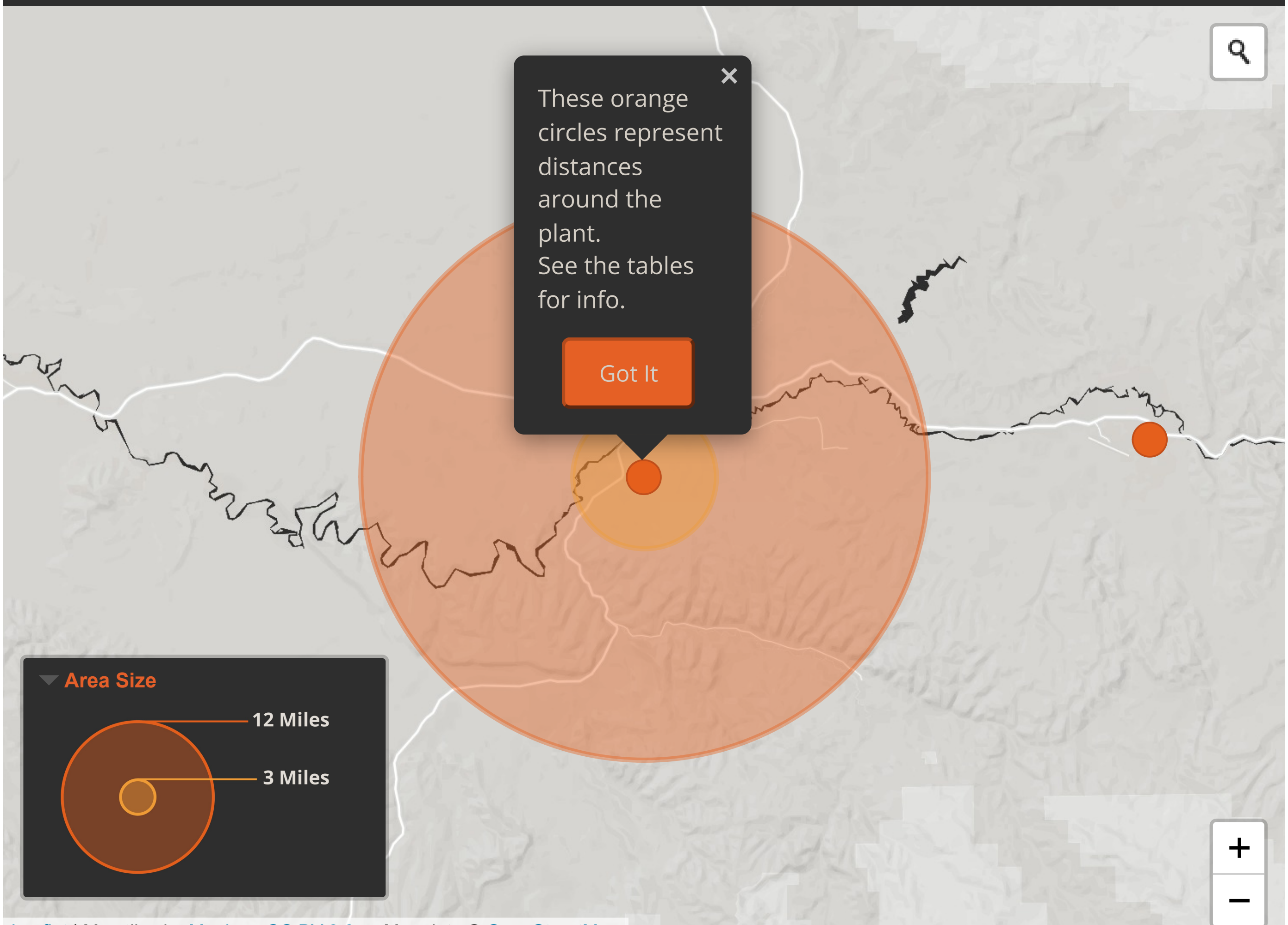
**Size of Plant** 1,304 MW

**In Service Date** 1979-1984

**$SO_2$ Emissions** 3,018 tons per year

**$NO_x$ Emissions** 7,985 tons per year

**$CO_2$ Emissions** 9,181,677 tons per year




Leaflet | Map tiles by Mapbox, CC BY 3.0 — Map data © OpenStreetMap

## Health Impacts

(per year)

**Deaths** 21

**Hospital Admissions** 2

**Asthma ER Visits** 5

**Heart Attacks** 8

## At Risk Population

| | 3 Miles | 12 Miles |
|---|---|---|
| **Population** | 410 | 12,135 |

**Acute Bronchitis** 14
**Asthma Attacks** 270
**Work Loss Days** 1,234

| | | |
|---|---|---|
| **Number of Children** | 123 | 3,642 |
| **Number of Schools** | -- | 13 |
| **Hospitals** | -- | 1 |
| **Nursing Homes** | 0 | 1 |
| **Places of Worship** | -- | 1 |
| **People of Color vs State Average** | 8% vs. 30% | 18% vs. 30% |
| **Poverty Rate vs State Average** | 4% vs. 13% | 11% vs. 13% |

CLEAN AIR TASK FORCE

Methodology

Powered by ZevRoss Spatial Analysis

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-26-21 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-161
SPP West Press Release

March 20, 2025

# SPP first RTO to operate in both interconnections with tariff approval

LITTLE ROCK, ARK. — Southwest Power Pool (SPP) will soon be the first regional transmission organization (RTO) in the U.S. to provide full services in both the Eastern and Western Interconnections of the nation's power grid. On March 20, the Federal Energy Regulatory Commission (FERC) unanimously approved Southwest Power Pool's amended tariff that includes provisions enabling Western members to join the RTO. The Commission's approval paves the way for seven Western entities, all of whom are participants in SPP's Western Energy Imbalance Service (WEIS) market today, to begin participating in SPP's Integrated Marketplace, transmission planning, reliability coordination and other RTO services beginning in April 2026.

On June 4, 2024, SPP filed its amended tariff with FERC to accommodate requirements for Western entities pursuing RTO membership or increased participation as part of the expansion of the SPP RTO: Basin Electric Power Cooperative; Colorado Springs Utilities; Deseret Power Electric Cooperative; the Municipal Energy Agency of Nebraska (MEAN); Platte River Power Authority; Tri-State Generation and Transmission Association; and the Western Area Power Administration Colorado River Storage Project, Rocky Mountain and Upper Great Plains regions.

“I am pleased to announce FERC's approval of the amended RTO tariff,” said Barbara Sugg, SPP president and CEO. “Expanding the RTO into the Western Interconnection is an exciting step in SPP's growth, bringing value to new and existing members while enhancing reliability in both interconnections.”

The expansion of the RTO is part of Aspire 2026, SPP's five-year strategic plan, which details opportunities to fully integrate Western facilities into SPP's existing market system in a way that creates meaningful, equitable value for new and existing members.

“The Western expansion of the SPP RTO bolsters reliability and resiliency for our members as we grow and diversify our resource portfolio while reducing emissions," said Tri-State Generation and Transmission Association CEO Duane Highley. “We greatly value the full benefits of the SPP RTO, including day-ahead and ancillary services markets, efficient regional transmission planning, a common transmission tariff and participatory governance model that help us to further reduce costs for our members across the West. Prior to SPP RTO West entry, we will be making a filing with our state regulators highlighting these market benefits.”

“SPP's RTO expansion into the Western Interconnect will help us to reduce our overall carbon footprint for MEAN's power resources through the economic dispatch of a wholesale power market and maximizing operational efficiencies of renewable resources,” said MEAN Director of Wholesale Operations Brad Hans. “As a member of SPP's RTO in the Eastern Interconnect for several years, MEAN recognizes the benefits of participating in that market and the energy cost savings it provides as well as SPP's member-driven business model."

"In 2018, when we outlined our plan to pursue a noncarbon energy portfolio, it was very clear to us that an integral component to this plan was to join a power market," shares Jason Frisbie, CEO and general manager of Platte River Power Authority. "Over the last seven years our teams across the organization have been dedicated to this effort working closely with SPP to be ready for the moment we join the RTO, which will help us integrate more renewable energy onto our system and manage our energy costs."

"With the complexities of today's energy industry and the regulations that define it, an adaptable electric grid with access to both local and regional resources is essential for managing customer costs and maintaining service reliability," said Colorado Springs Utilities Chief Executive Officer Travas Deal. "We strongly believe the SPP RTO will help us achieve this goal, while also connecting us with vital transmission resources as we pursue new and cleaner forms of electric generation. So, FERC's approval of the amended tariff is very encouraging for us and our customers as we implement our Sustainable Energy Plan."

SPP is working with additional Western utilities who have expressed interest in joining the RTO once this initial expansion is complete.

Separately, SPP is developing Markets+, another market designed to bring significant incremental value to the Western Interconnection. SPP received FERC's approval of the Markets+ tariff in January, and is working with interested parties to finalize plans to fund the market's development and launch. With the addition of Markets+, SPP will have a solid presence in the West, operating two markets and serving as the program administrator for the Western Power Pool's Western Resource Adequacy Program (WRAP).

"Multiple markets maximize value for all participants," said Sugg. "SPP has operated a Western market since 2021, and with the expansion of the RTO's Integrated Marketplace in 2026 and launch of Markets+ in 2027, we're looking forward to bringing additional affordability, reliability, equity and sustainability to the West."

SPP first earned FERC's approval as an RTO in October 2004, and over the last two decades has expanded its RTO footprint in the Eastern Interconnection from eight to 14 states. This expansion would grow SPP's RTO service territory to encompass all or part of 17 states. SPP has been engaged with parties interested in evaluating the benefits and requirements of RTO membership in the Western Interconnection since Oct. 20, 2020. The SPP board of directors approved the initial RTO expansion terms and conditions in July 2021, the DC tie terms and conditions in July 2022 and the WAPA Colorado River Storage Project terms and conditions in January 2023. The expansion of the SPP RTO is scheduled to go live April 1, 2026.

**Meghan Sever, 501-482-2393, msever@spp.org**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-26-21 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-162
EIA Generating Unit Annual Capital and Life Extension Costs Analysis

Independent Statistics & Analysis
U.S. Energy Information Administration

# Generating Unit Annual Capital and Life Extension Costs Analysis

December 2019

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

# Generating Unit Annual Capital and Life Extension Costs Analysis

In a period of accelerating retirements of electric power generators, EIA sought to revisit its assumptions of age-related generation costs. EIA commissioned Sargent & Lundy (S&L) to evaluate capital expenditures (CAPEX) and operations and maintenance (O&M) costs for non-nuclear generating units, with a particular emphasis on how costs of coal and other fossil-fueled plants change over time. The following report represents S&L's findings. A separate EIA report, *Updates to Cost Assumptions in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)*,[1] details subsequent updates to the EMM module.

The following report was accepted by EIA in fulfillment of contract number DE-EI0003250. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of the findings contained herein. Responsibility for accuracy of the information contained in this report lies with the contractor. Although intended to be used to inform the updating of EIA's EMM module of NEMS, EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

[1] https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/addendum.pdf

Prepared by

Sargent & Lundy Consulting

55 East Monroe Street
Chicago, Illinois 60603-5780

**FINAL**

# Generating Unit Annual Capital and Life Extension Costs Analysis

## Final Report on Modeling Aging-Related Capital and O&M Costs

Prepared for

eia

U.S. Energy Information Administration

SL-014201
May 2018

Project 13651-001

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**Sargent & Lundy** is a full-service architect-engineering firm that has been dedicated exclusively to the electric power industry for over 125 years. Sargent & Lundy has provided comprehensive planning, development, permitting, technical and financial consulting, engineering, design, construction management, and commissioning services for electric power generation and power delivery projects—1,557 clients in 88 countries worldwide—since its founding in 1891. Having designed 958 power plants, totaling 140,667 MW of electric generation capacity, Sargent & Lundy is regarded as one of the oldest, largest, and most experienced power generation engineering companies in the U.S.

Sargent & Lundy's roles on electric power generation projects include full-design architect-engineer, owner's engineer, lender's independent engineer/technical advisor, and consultant. Our services include specialized technical advisory and consulting services to complete engineering and program management, encompassing procurement, construction management, technology transfer, and assistance with construction. Sargent & Lundy provides professional consulting, engineering, and design services throughout the lifecycle of power generation projects, from project concept and development, through detailed design and procurement, to construction and operation.

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# CONTENTS

Section | Page

# CONTENTS

# CONTENTS

# CONTENTS

# CONTENTS

# CONTENTS

# CONTENTS

# TABLES AND FIGURES

Table or Figure | Page

# TABLES AND FIGURES

Table or Figure | Page

# TABLES AND FIGURES

Table or Figure | Page

# TABLES AND FIGURES

# TABLES AND FIGURES

Table or Figure | Page

# TABLES AND FIGURES

# ACRONYMS AND ABBREVIATIONS

| Term | Definition or Clarification |
|---|---|
| 2017$ | 2017 dollars |
| A&G | Administrative and general |
| AEO | *Annual Energy Outlook* |
| ARIMA | Autoregressive integrated moving average |
| ATB | Annual Technology Baseline |
| CAPEX | Capital expenditures |
| CC | Combined cycle |
| CF | Capacity factor |
| COD | Commercial operation date |
| CT | Combustion turbine |
| DOE | Department of Energy |
| EIA | Energy Information Administration |
| EMM | Electricity Market Module |
| ESP | Electrostatic precipitator |
| FERC | Federal Energy Regulatory Commission |
| FERC Form 1 | FERC Form No. 1 |
| FGD | Flue gas desulfurization |
| Hg | Mercury |
| HP | High pressure |
| ID | Identifier or induced draft |
| IP | Intermediate pressure |
| IPP | Independent power producer |
| IRENA | International Renewable Energy Agency |

# ACRONYMS AND ABBREVIATIONS

| Term | Definition or Clarification |
|---|---|
| kW | Kilowatts |
| kW-yr | Kilowatt-years |
| LCOE | Levelized cost of electricity |
| LP | Low pressure |
| MMRA | Major maintenance reserve account |
| MW | Megawatts |
| MWh | Megawatt-hours |
| $NO_X$ | Nitrogen oxide |
| NREL | National Renewable Energy Laboratory |
| OEA | Office of Energy Analysis |
| O&M | Operations and maintenance |
| PM | Particulate matter |
| PV | Photovoltaic |
| $R^2$ | R-squared |
| Sargent & Lundy | Sargent & Lundy LLC |
| $SO_2$ | Sulfur dioxide |
| TCP | Total Cost of Plant |

# EXECUTIVE SUMMARY

## IDENTIFYING IMPACTS OF AGING ON GENERATION COST AND OPERATION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

For most types of generators evaluated, we did not find a statistically significant relationship between plant age and costs (both CAPEX and O&M). CAPEX spending over the life of each plant represents a series of capital projects—rather than a single life extension project—that includes both discretionary spending and vendor-specified spending. For discretionary spending, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Vendor-specified spending is primarily for major maintenance, typically based on cumulative hours of operation and/or cumulative starts, and more commonly applied to gas/oil CC and CT plants. We did, however, find a statistically significant relationship between age and CAPEX spending for fossil steam coal generators with flue gas desulfurization (FGD) equipment, and between age and O&M spending for conventional hydroelectric plants and wind turbines. We also found age and CAPEX spending to be significantly correlated for CC and CT plants, although measured in terms of operating hours or starts, rather than years. Table ES-1 summarizes the variables found to have a significant effect on annual changes in real spending per kilowatt (kW) for each generator type. We recommend the EIA incorporate these variables in the EMM representation of CAPEX and O&M.

**Table ES-1 — Variables Affecting Annual Changes in Real Spending per kW**

| Generating Capacity | CAPEX Spending | O&M Spending |
|---|---|---|
| Coal Steam Plants | Age and FGD (see Table ES-3) | - |
| Gas/Oil Steam Plants | Capacity (see Table ES-5) | - |
| Gas/Oil Combined-Cycle Plants | Operating Hours (see Table ES-7) | - |
| Gas/Oil Combustion Turbines | Starts (see Table ES-7) | - |
| Conventional Hydropower | - | Age (Regression Equation) |
| Pumped Storage – Hydraulic Turbine Reversible | - | - |
| Solar Thermal – Central Tower | - | - |
| Solar Photovoltaic – Single-Axis Tracking | - | - |
| Geothermal | - | - |
| Wind | Capacity (see Table ES-11) | Age (Regression Equation) |

While we did not find a consistent relationship between aging and CAPEX and O&M costs, changes in performance-related factors and external market conditions are also related to changes in these costs over time. Examples of these factors and conditions include the following:

- Plant efficiency (heat rate)
- Capacity degradation
- Outage rates
- Market prices (electricity, fuel)

These factors and conditions were not part of the scope of our study. We recommend the EIA consider studying these in the future.

## MODELING IMPACTS OF AGING IN EIA PROJECTIONS

### Existing Treatment of Aging in EIA's Electricity Market Module

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX that is intended to extend the life or preserve the performance of an existing generator. In the EMM, costs for plant O&M do not vary with plant age.

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is $0.18 per kilowatt-year (/kW-year) for existing CC plants, $9/kW-year for existing gas/oil steam plants, and $18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to $7.25/kW-year, $16/kW-year, and $25/kW-year, respectively, after a plant reaches 30 years of age.[1] The average annual CAPEX in the EMM for existing CT plants is $1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

### Need for Update to EIA's Treatment of Aging

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 ("FERC Form 1").[2] The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy's update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

[1] Internal communication with EIA, February 2018.
[2] FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.
2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed ($/kW-year) or variable ($/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in Section 2.

## ANALYSIS OF AGING IMPACTS IN PUBLICLY-REPORTED COST INFORMATION

### Cost Breakdowns in Reported Data

Our analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

The reporting formats of our in-house data and the FERC Form 1 data have a clear delineation between CAPEX and O&M. However, while the in-house data often contains an explicit breakdown between fixed and variable O&M, the FERC Form 1 accounts for O&M are not categorized as such. Rather, the reported O&M costs in a given account are the combined fixed and variable costs at the reported generating output. Thus, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data.

O&M costs for the following technologies are essentially all fixed: solar thermal (central tower), solar PV (single-axis tracking), geothermal, and wind. By definition, fixed O&M costs are independent of plant generation, so they are expressed in $/kW-year.

O&M costs for the following technologies include a significant variable component: coal steam, gas/oil steam, gas/oil CC, gas/oil CTs, conventional hydropower, and pumped storage (hydraulic turbine reversible). By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh.

As mentioned, the variable O&M components cannot be clearly delineated from the total reported O&M costs. For this assessment, the variable components were combined with the fixed components and expressed in $/kW-year. The combined total O&M was found to correspond to the combined total O&M representation in the EMM, which includes a $/MWh variable O&M breakout, as presented in the subsections below.

CAPEX spending values, expressed in $/kW-year, were derived from the new dataset as an additive to the EMM O&M costs and as replacements for the existing EMM CAPEX representation for all technologies, except for gas/oil CC and gas/oil CTs. CAPEX spending for gas/oil CC and gas/oil CTs was found to be primarily for major maintenance events, which are already represented as a $/MWh variable O&M cost in the EMM.

### Data Compilation

The data compilation for this analysis consisted of the following annual plant data (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant megawatts (MW) (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

All available and validated cost data over the plant operating life, historical or forecasted, was normalized as follows for each plant:

- Annual O&M in 2017 $/kW-year versus age (years from commercial operation date [COD])
- Annual CAPEX in 2017 $/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

In all cases, the yearly values are expressed in constant 2017 price levels and would increase annually with the inflation rate.

## IDENTIFYING CHANGES IN SPENDING PATTERNS OVER PLANT LIFE

### Differences in Spending Approach by Plant Type

CAPEX spending over the life of each plant represents a series of capital projects throughout the plant life, rather than a single life extension project. This consists of both discretionary spending and vendor-specified spending, examples of which are as follows:

- Discretionary spending is notable for most coal steam and gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Typical industry-standard frequencies for repairs and replacements of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.
- Vendor-specified major maintenance spending, such as commonly applied to gas/oil CC and gas/oil CTs, is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:
    - Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
    - Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

### Potential Benefits of CAPEX and O&M Spending on Future Spending

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

### Potential Impacts of Plant Age on Future Spending

The spending characteristics described in the previous subsections are evident in the datasets, which reveal significant variability in plant spending as a function of age. Sargent & Lundy's evaluation therefore examined additional variables that might explain some of the variability in age-related spending: plant capacity (MW), capacity factor, external market conditions, regulatory environment, fuel characteristics, and FGD. These additional variables and their effects are described in the following subsections.

### Effect of Plant Capacity (MW)

The effect of plant MW capacity on age-related spending, expressed in $/kW-year, was examined by breaking the dataset into separate plant size categories, summarized as follows:

- Coal Steam
  - All MW
  - < 500 MW
  - 500 MW – 1,000 MW
  - 1,000 MW – 2,000 MW
  - > 2,000 MW
- Gas/Oil Steam
  - < 500 MW
  - 500 MW – 1,000 MW
  - > 1,000 MW
- Gas/Oil CC
  - All MW
  - < 500 MW
  - 500 MW – 1,000 MW
  - > 1,000 MW
- Gas/Oil CT
  - All MW
  - < 100 MW
  - 100 MW – 300 MW
- Conventional Hydroelectric
  - All MW
  - < 100 MW
  - 100 MW – 500 MW
  - > 500 MW
- Pumped Hydroelectric Storage
  - All MW
  - < 100 MW
  - 100 MW – 500 MW
  - > 500 MW
- Solar Photovoltaic
  - < 5 MW
  - > 5 MW
- Wind Turbine
  - All MW
  - < 100 MW
  - 100 MW – 200 MW
  - > 200 MW

For some of the MW breakdowns above, the age coefficient in the regression analysis of CAPEX or O&M was found to be statistically significant. For the other MW breakdowns, an average value by age group was found to be more appropriate (see Table ES-1).

### Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure ES-1. A similar decline also occurred with the gas/oil steam plants, as shown in Figure ES-2.

**Figure ES-1 — Capacity Factor vs. Age for All Coal Plants**

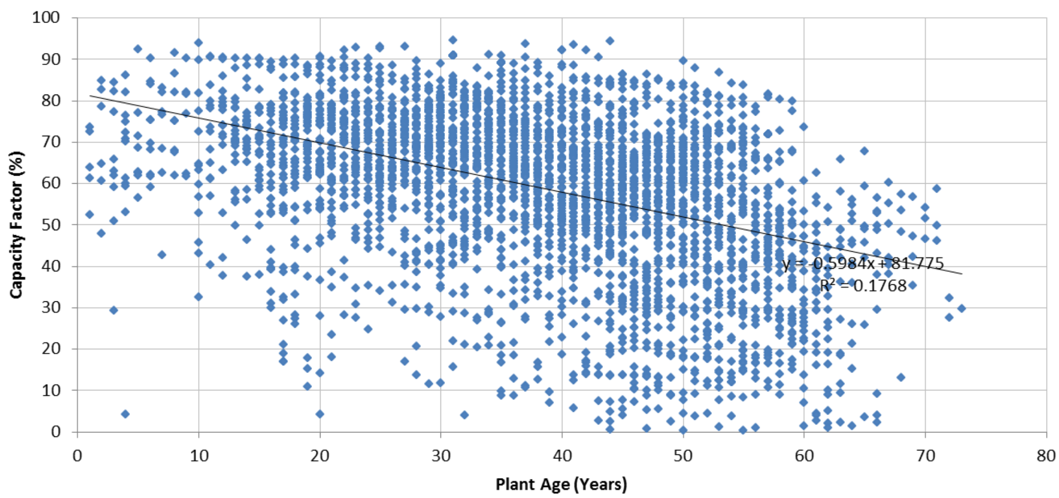
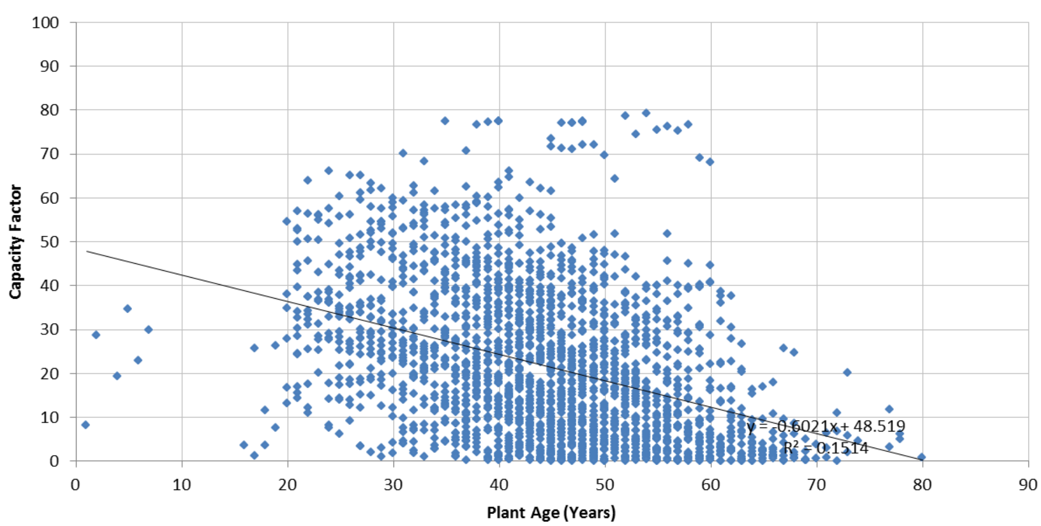



**Figure ES-2 — Capacity Factor vs. Age for All Gas/Oil Steam Plants**



### Effect of External Market Conditions

The declining capacity factors with age, shown above, may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam and gas/oil steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam and gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.[3]

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam and gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their plant lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table ES-2 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

[3] Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

**Table ES-2 — High Capacity Factor Coal Plants – Spending Comparison**

| | Average – All Years | Years 1-20 | Years 20-40 | Years 40-80 |
|---|---|---|---|---|
| Capacity Factor – All Plants | 59.1% | 66.8% | 64.5% | 52.9% |
| Capacity Factor – High CF Plants | 74.0% | - | 72.8% | 74.4% |
| O&M – All Plants (2017 $/kW-yr) | 46.01 | 53.90 | 40.06 | 48.77 |
| CAPEX – All Plants (2017 $/kW-yr) | 22.78 | 17.92 | 26.20 | 21.25 |
| Total – All Plants (2017 $/kW-yr) | 68.67 | 71.86 | 66.25 | 69.82 |
| O&M – High CF Plants (2017 $/kW-yr) | 36.65 | - | 31.07 | 38.78 |
| CAPEX – High CF Plants (2017 $/kW-yr) | 20.26 | - | 23.13 | 19.16 |
| Total – High CF Plants (2017 $/kW-yr) | 57.02 | - | 54.20 | 58.10 |

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

### Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states. Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

### Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types. The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

### Effect of Flue Gas Desulfurization

The regression analysis indicated a significant difference in CAPEX spending for coal plants with FGD. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

## PROPOSED UPDATES TO EMM METHODOLOGY

The EMM captures changes in age-related spending patterns through multiple cost categories: CAPEX, O&M, fuel, energy sales, and capacity sales. The updates below relate only to the CAPEX and O&M. The focus of the work scope was to more accurately represent power plant aging impacts on CAPEX and O&M. Detailed derivations of fixed and variable O&M costs for the EMM were not part of the work scope.

Sargent & Lundy's recommended updates to the fixed and variable O&M costs and CAPEX in the EMM for each generating technology are summarized in the tables below. Values are in constant 2017 price levels and are incurred in every year of plant operation, starting from commercial operation through plant retirement. In all cases, the yearly values would increase annually with the inflation rate.

### Coal Steam

Sargent & Lundy's analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): age and FGD. Variables not having a significant effect on annual changes in real CAPEX spending (on a constant $/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-3 compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

**Table ES-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors**

| Net Total CAPEX (2017 $/kW-year) | $/kW-yr (Years 1-10) | $/kW-yr (Years 10-20) | $/kW-yr (Years 20-30) | $/kW-yr (Years 30-40) | $/kW-yr (Years 40-50) | $/kW-yr (Years 50-60) | $/kW-yr (Years 60-70) | $/kW-yr (Years 70-80) |
|---|---|---|---|---|---|---|---|---|
| New Value – No FGD* | 17.16 | 18.42 | 19.68 | 20.94 | 22.20 | 23.46 | 24.72 | 25.98 |
| New Value – with FGD* | 22.84 | 24.10 | 25.36 | 26.62 | 27.88 | 29.14 | 30.40 | 31.66 |
| Existing EMM Value | 17.55 | 17.55 | 17.55 | 24.62 | 24.62 | 24.62 | 24.62 | 24.62 |

*Calculated to the midpoint of the given age band.

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in $/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table ES-4).

**Table ES-4 — Coal Steam O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh)* | Variable O&M (2017 $/kW-yr)** | Total O&M (2017 $/kW-yr)** |
|---|---|---|---|---|
| Coal Steam Dataset Results – All Plants | 36.81 | 1.78 | 9.20 | 46.01 |
| < 500 MW | 44.21 | 1.78 | 9.20 | 53.41 |
| 500 MW – 1,000 MW | 34.02 | 1.78 | 9.20 | 43.22 |
| 1,000 MW – 2,000 MW | 28.52 | 1.78 | 9.20 | 37.72 |
| > 2,000 MW | 33.27 | 1.78 | 9.20 | 42.47 |
| Existing EMM Value*** | 40.63 | 1.78 | 9.20 | 49.83 |

*Fixed and variable split is estimated using the existing EMM variable O&M cost of $1.78/MWh.
**Calculated at the coal steam dataset average capacity factor of 59%.
***Source: Internal communication with EIA, February 2018.

### Gas/Oil Steam

The analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-5 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

**Table ES-5 — Gas/Oil Steam CAPEX Results**

| Plant Size | Net Total CAPEX (2017 $/kW-year) | |
|---|---|---|
| | Years 1-30 | Years 30-80 |
| Gas/Oil Steam Dataset Results – All Plants | 15.96 | 15.96 |
| New Value: < 500 MW | 18.86 | 18.86 |
| New Value: 500 MW – 1,000 MW | 11.57 | 11.57 |
| New Value: > 1,000 MW | 10.82 | 10.82 |
| Existing EMM Value | 9.14 | 16.21 |

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRAs are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table ES-6). However, the variable O&M of $8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of $1.78/MWh in the EMM used for the coal units.

**Table ES-6 — Gas/Oil Steam O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh)* | Variable O&M (2017 $/kW-yr)** | Total O&M (2017 $/kW-yr)** |
|---|---|---|---|---|
| Gas/Oil Steam Dataset Results – All Plants | 24.68 | 1.00 | 1.84 | 26.52 |
| < 500 MW | 29.73 | 1.00 | 1.84 | 31.57 |
| 500 MW – 1,000 MW | 17.98 | 1.00 | 1.84 | 19.82 |
| > 1,000 MW | 14.51 | 1.00 | 1.84 | 16.35 |
| Existing EMM Value*** | 19.68 | 8.23 | 15.14 | 34.82 |

*Fixed and variable split is estimated using an approximate value for variable O&M of $1.00/MWh based on confidential projects.
**Calculated at the gas/oil steam dataset average capacity factor of 21%.
***Source: Internal communication with EIA, February 2018.

### Gas/Oil Combined Cycle and Gas/Oil Combustion Turbine

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC and gas/oil CT plants represents a series of capital projects throughout the plant life, which include projects for "life extension." Most CAPEX spending for gas/oil CC and gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs described in the previous subsection, major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table ES-7 compares the new CAPEX and O&M values derived from the gas/oil CC and CT datasets with the values currently used in the EMM. As indicated above, the combined CAPEX and O&M values in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC and CT plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of $7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the $/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

- The EMM fixed and variable O&M costs for CT plants are high for all plant sizes. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

**Table ES-7 — Gas/Oil CC and CT CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh)* | Variable O&M (2017 $/kW-yr)* | Total O&M (2017 $/kW-yr)* | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr)** |
|---|---|---|---|---|---|---|
| CC Dataset Results (All Plants) | 13.08 | 3.91 | (included in CAPEX) | 13.08 | 15.76 | 28.84 |
| < 500 MW | 15.62 | 4.31 | (included in CAPEX) | 15.62 | 17.38 | 33.00 |
| 500 MW – 1,000 MW | 9.27 | 3.42 | (included in CAPEX) | 9.27 | 13.78 | 23.05 |
| > 1,000 MW | 11.68 | 3.37 | (included in CAPEX) | 11.68 | 13.57 | 25.25 |
| Existing EMM Value** | 27.52 | 2.64 | 10.64 | 38.16 | 0.18; 7.25 (after year 30) | 38.34; 45.41 (after year 30) |
| | | | | | | |
| CT Dataset Results (All Plants) | 5.33 | (starts based) | (included in CAPEX) | 5.33 | 6.90 | 12.23 |
| < 100 MW | 5.96 | (starts based) | (included in CAPEX) | 5.96 | 9.00 | 14.96 |
| 100 MW – 300 MW | 6.43 | (starts based) | (included in CAPEX) | 6.43 | 6.18 | 12.61 |
| > 300 MW | 3.99 | (starts based) | (included in CAPEX) | 3.99 | 6.95 | 10.94 |
| Existing EMM Value*** | 12.60 | 14.63 | 5.13 | 17.73 | 1.52 | 19.25 |

*Fixed and variable split is estimated, assuming all CAPEX costs are represented as variable O&M, either hours-based ($/MWh) or starts-based ($/start).
**Calculated at the dataset average capacity factor of 46% for CC and 4% for CT.
***Source: Internal communication with EIA, February 2018.

### Conventional Hydroelectric

Overall, the conventional hydroelectric dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. The average CAPEX value over all operating years is $22.56/kW-year. The dataset does support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 22.360 + (0.073 × age)**

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table ES-8) and outside the range of values published in the AEO[4] and by the International Renewable Energy Agency (IRENA).[5] The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

**Table ES-8 — Hydroelectric CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Conventional Hydroelectric Dataset Results – All Plants | 22.00 | - | 22.56 | 44.56 |
| Existing EMM Value* | 14.58 | 0.00 | 0.00 | 14.58 |

*Source: Internal communication with EIA, February 2018.

### Pumped Storage

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is $14.83/kW-year for CAPEX and $23.63/kW-year for O&M (Table ES-9). The existing values used in the EMM are not available.

**Table ES-9 — Pumped Storage CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Pumped Storage Dataset Results – All Plants | 23.63 | - | 14.83 | 38.46 |
| Existing EMM Value | N/A | N/A | N/A | N/A |

### Solar Photovoltaic

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Sargent & Lundy notes that the average change in the "Total Cost of Plant" (TCP) reported in the FERC data for the limited usable dataset (15 sites not filtered out) is approximately $26/kW-year. However, due to the limited dataset, lack of clarity on what qualifies as a change to the TCP, and general lack of

[4] Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.
[5] International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

consistency in the FERC capital cost data provided, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based upon closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old.

When considering the average O&M costs per plant as a single data point and then averaging those values, Sargent & Lundy calculated an average O&M cost of $75/kW-year from the FERC data for sites under 5 MW. Using the same method, an average O&M cost of $15/kW-year was calculated from the FERC data for sites over 5 MW.

By comparison, the EMM uses an average O&M value of $28.47/kW-year for all solar PV plants and an average CAPEX value of zero. Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

### Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

### Geothermal

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated $/kW-year average in Table ES-10 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

**Table ES-10 — Geothermal CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Geothermal Dataset Results – All Plants | 157.10 | - | 40.94 | 198.04 |
| Existing EMM Value** | 91.66 | 0.00 | 0.00 | 91.66 |

**Source: Internal communication with EIA, February 2018.

### Wind

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table ES-11. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

**Table ES-11 — Wind CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) |
|---|---|---|---|
| Wind Dataset Results – All Plants | 31.66 + (1.22 × age) | 0.00 | 18.29 |
| < 100 MW | 39.08 + (1.12 × age) | 0.00 | 20.48 |
| 100 MW – 200 MW | 23.80 + (1.17 × age) | 0.00 | 16.93 |
| > 200 MW | 26.78 + (0.92 × age) | 0.00 | 13.48 |
| Existing EMM Value* | 29.31 | 0.00 | 0.00 |

*Source: Internal communication with EIA, February 2018.

## RECOMMENDED AREAS FOR FURTHER STUDY

Based on our analyses performed for the update to the EMM treatment of age-related spending, Sargent & Lundy identified several areas that warrant further study, including:

- Impact of regional labor cost differences versus the effects of a regulated/deregulated environment;
- Compatibility of EMM plant technology and size breakdowns and fixed/variable O&M cost breakdowns with proposed EMM updates;
- Identification of the factors supporting consistently high capacity factors over the plant lives at particular coal units; and
- Impact of aging on plant performance (heat rates, capacity derates, etc.). If capacity factors decline, regardless of the causes, this includes examining the impact of the lower capacity factors on plant costs and performance.

**SARGENT & LUNDY, L.L.C.**

Prepared by:

| | |
|---|---|
| Terrence P. Coyne<br>Senior Consultant | Patrick S. Daou<br>Consultant |
| Eric R. DeCristofaro<br>Senior Consultant | Marc E. Lemmons<br>Project Associate |
| Sean P. Noonan<br>Senior Consultant | Ryan M. Swanson<br>Senior Consultant |
| John R. Wroble<br>Principal Consultant | |

Reviewed by:

Patrick M. Geenen
Project Manager

Approved by:

Matthew R. Thibodeau
Vice President

May 7, 2018
Date

# 1. INTRODUCTION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

This final report is the fourth milestone task of the EMM update project, which is organized as follows:

- Task 1 – Analysis of publicly available information for use in estimating capital costs related to ongoing operations for specified plant types.

- Task 2 – Analysis of publicly available information for use in estimating changes in O&M expenditures due to aging for specified plant types.
- Task 3 – Interim report on assembled aging-related capital and O&M costs.
- Task 4 – Final report on modeling aging-related capital and O&M costs.

# 2. ASSESSMENT METHODOLOGY

## 2.1 BACKGROUND

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX. These added expenditures are intended to extend the life or preserve the performance of an existing generator, including repowering, major repairs or retrofits, and/or covering increases in maintenance required to mitigate the adverse effects of aging, including any decreases in plant performance. The portion of the annual CAPEX associated with the step increase is referred as “life extension costs.”

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is $0.18 per kilowatt-year (/kW-year) for existing CC plants, $9/kW-year for existing gas/oil steam plants, and $18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to $7.25/kW-year, $16/kW-year, and $25/kW-year, respectively, after a plant reaches 30 years of age.[6] The average annual CAPEX in the EMM for existing CT plants is $1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 (“FERC Form 1”).[7] The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy’s update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.

[6] Internal communication with EIA, February 2018.
[7] FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed ($/kW-year) or variable ($/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in the following subsections.

## 2.2 SOURCES OF COST INFORMATION

### 2.2.1 FERC Form 1 Data

Sargent & Lundy reviewed the FERC Form 1 data through 2016, financial information available from other publicly available sources, and detailed in-house project information with which we are familiar. We assembled a sufficient volume of source material for each technology in order to characterize the distribution of capital and O&M expenditures over the life of a plant.

We obtained the FERC Form 1 data via ABB's Velocity Suite EV Power database. Using the available FERC Form 1 data, we assessed and summarized the "Cost of Plant" components of the data by major plant type category. The "Cost of Plant" components include the following categories of "Electric Plant in Service" accounts in FERC Form 1 data, which have been reported annually since the database's inception:

- Steam Power Generation – Cost of Plant
  - 310 Land and land rights.
  - 311 Structures and improvements.

    - 312 Boiler plant equipment.
    - 313 Engines and engine-driven generators.
    - 314 Turbo generator units.
    - 315 Accessory electric equipment.
    - 316 Miscellaneous power plant equipment
    - 317 Asset retirement costs for steam production plant.
- Hydraulic Power Generation – Cost of Plant
    - 330 Land and land rights.
    - 331 Structures and improvements.
    - 332 Reservoirs, dams, and waterways.
    - 333 Water wheels, turbines, and generators.
    - 334 Accessory electric equipment.
    - 335 Miscellaneous power plant equipment.
    - 336 Roads, railroads, and bridges.
    - 337 Asset retirement costs for hydraulic production plant.
- Other Power Generation – Cost of Plant
    - 340 Land and land rights.
    - 341 Structures and improvements.
    - 342 Fuel holders, producers, and accessories.
    - 343 Prime movers.
    - 344 Generators.
    - 345 Accessory electric equipment.
    - 346 Miscellaneous power plant equipment.
    - 347 Asset retirement costs for other production plant.

The sum of these components includes the original construction cost and all ongoing CAPEX. Therefore, each annual FERC Form 1 submittal includes the cumulative additions to the "Total Cost of Plant" (TCP). Annual changes in the TCP between each submittal year give an indication of the amount of CAPEX for the given year. Sargent & Lundy assessed and summarized these annual changes to derive age-related CAPEX, as discussed in the following subsections.

Sargent & Lundy also assessed and summarized the annual O&M expenditures for each technology as reported under the "Electric Operation and Maintenance Expenses" accounts in FERC Form 1:

- Steam Power Generation – O&M
    - 500 Operation supervision and engineering.
    - 502 Steam expenses.
    - 505 Electric expenses.
    - 506 Miscellaneous steam power expenses.
    - 507 Rents.
    - 509 Allowances.
    - 510 Maintenance supervision and engineering.
    - 511 Maintenance of structures.
    - 512 Maintenance of boiler plant.
    - 513 Maintenance of electric plant.
    - 514 Maintenance of miscellaneous steam plant.
- Hydraulic Power Generation – O&M
    - 535 Operation supervision and engineering.
    - 536 Water for power.
    - 537 Hydraulic expenses.
    - 538 Electric expenses.
    - 539 Miscellaneous hydraulic power generation expenses.
    - 540 Rents.
    - 541 Maintenance supervision and engineering.
    - 542 Maintenance of structures.
    - 543 Maintenance of reservoirs, dams, and waterways.
    - 544 Maintenance of electric plant.
    - 545 Maintenance of miscellaneous hydraulic plant.
- Other Power Generation – O&M
    - 546 Operation supervision and engineering.
    - 548 Generation expenses.
    - 549 Miscellaneous other power generation expenses.
    - 550 Rents.
    - 551 Maintenance supervision and engineering.
    - 552 Maintenance of structures.
    - 553 Maintenance of generating and electric plant.
    - 554 Maintenance of miscellaneous other power generation plant.

The above O&M expenditures are reported for individual power plants. Administrative and general (A&G) expenses in FERC accounts 920 through 935 are reported for the entire utility company. A&G expenses in these accounts were not included in this evaluation because of the significant differences in company sizes, mix of resources, and methods of allocating costs to individual power plants. In a similar manner, corporate-level A&G costs were also excluded from Sargent & Lundy's internal data.

The above FERC accounts 500 to 554 correspond to the following fixed and variable O&M components:

- Fixed O&M
  - Labor
  - Maintenance materials
  - Supplies and miscellaneous expenses
- Variable O&M
  - Consumables (chemicals, water, waste disposal, etc.)
  - Other costs proportional to generating output

The FERC accounts do not explicitly break out labor costs, as most of the accounts include both labor and non-labor expenditures. Likewise, the FERC accounts are not categorized according to fixed and variable cost components. The O&M costs in a given account are combined fixed and variable costs at the reported generating output.

### 2.2.2 Sargent & Lundy Internal Data

In addition, Sargent & Lundy compared publicly available, non-fuel-related financial and cost data with a characterization of proprietary information with which we are familiar, to the extent permissible by applicable confidentiality agreements (information about plant location, equipment type, or plant configuration was never disclosed from the proprietary data). We utilized our knowledge of actual projects to assemble a characterization of life extension/repowering costs from our in-house data.

A large portion of the in-house data used in this report was developed from business plan forecasts that capture actual budgeted costs for scheduled projects as well as longer-term projections. Historical spending data for standalone projects was not usable for this analysis, unless Sargent & Lundy had access to the complete O&M or CAPEX spending totals at a given plant for a given year. For consistent comparisons with other plants over time, each O&M or CAPEX data point needed to represent a comprehensive total of all spending projects.

### 2.2.3 Other Data Sources

Other publicly available data sources were searched, including regulated utility filings with public utility commissions, routine financial reports for publicly traded companies, utility integrated resource plans, data reported by various municipalities and electric cooperatives, and requests for proposals (RFPs) for plant improvements at public power entities. Cost data from each of these sources was found to be unsuitable for this study for one or more of the following reasons:

- Cost data was for initial capital investment costs only, with no O&M or ongoing CAPEX spending reported;
- Annual O&M or annual CAPEX amounts were for limited purposes and not representative of a complete year; and/or
- Annual O&M and annual CAPEX amounts were aggregated across business units and not assigned to specific plants.

Several publications or studies of power plant aging and life extension costs were used, which are cited herein.

## 2.3 DATA VALIDATION

Sargent & Lundy's approach to validating the FERC Form 1 data involved the following steps (note that capitalized words are proper FERC Form 1 terms):

1. For each Plant/Prime Mover combination (e.g., steam turbine, CC, simple-cycle CT), determine the difference between the prior and current year TCP reported in the FERC data. Note that a plant can have multiple prime movers on site (e.g., CT units and steam turbine units). Fortunately, that data is reported separately.
2. Flag and invalidate any years where the difference is negative (i.e., a decreasing value of the TCP).
3. Identify if the TCP difference is significantly due to asset retirement costs. If so, flag this plant reporting year consider it invalid, as capital would have been spent on non-aging items.
4. Identify if there has been any year-to-year change in nameplate capacity. If so, flag this plant reporting year and consider it invalid, because the TCP would be assumed to be spent on an expansion or addition.
5. Identify if any sulfur dioxide ($SO_2$), nitrogen oxide ($NO_X$), particulate matter (PM), or mercury (Hg) control equipment was installed for the plant reporting year. If so, flag that plant reporting year and consider it invalid, because capital would have been spent on non-aging items. The year

prior to or after the actual emissions control installation date is sometimes flagged as well, because of when the spending occurred (this is usually a judgement call).

6. Identify if any unit at the plant has been retired in a plant reporting year. If so, flag that plant reporting year and consider invalid, because capital would have been spent on non-aging items. Also, if the plant's TCP dropped significantly the last few years before retirement, flag those plant reporting years and consider them invalid.
7. Cross-check if any additional units at the plant site (using the same technology) show too great of time duration between installed dates of the units. If the first unit and the last unit installed is greater than 10 years apart, then flag the data and consider it invalid, because the TCP difference would not reflect the actual age of the plant (considered to be the age of the first unit). This was flagged as "Removed due to non-equal units at site."
8. If any TCP is reported to be zero for most of all of the reporting years of the plant, consider the data invalid.
9. If the TCP difference is highly volatile, flag and invalidate at discretion. For example, if one year TCP drops from $2,000/kW-year to $1,000/kW-year and then back to $2,000/kW-year in the year after, this would be considered highly volatile for those two reporting years.
10. If a reporting plant has only one or two years of reported TCP data, flag the plant and do not use its data.
11. If any plant reports negative Total O&M Costs, flag that year and do not use it.
12. Use only data that is valid for both CAPEX spending and O&M spending in the analysis of combined CAPEX and O&M spending. Otherwise, analyze CAPEX spending and O&M spending separately. Sargent & Lundy found that a large portion of the data points determined to be valid for CAPEX spending were also valid for O&M spending.

The resulting data points from this validation process are summarized in Table 2-1.

For each year of plant data, we also compiled the associated nameplate capacity (MW) and annual generation (MWh). EIA Form 860 was used to confirm the plant technology, environmental equipment, year in service, and other attributes.

## Table 2-1 — Summary of Valid Data Points

| Technology / (Dataset Identifier) | Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|---|
| | | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| Coal (10) | All MW | All | 3,713 | 3,098 | 3,109 | 655 | 615 |
| | < 500 MW | All | 1,592 | 1,274 | 1,284 | 318 | 318 |
| | 500 MW – 1,000 MW | All | 986 | 689 | 689 | 337 | 297 |
| | 1000 MW – 2,000 MW | All | 813 | 813 | 814 | 0 | 0 |
| | > 2,000 MW | All | 322 | 322 | 322 | 0 | 0 |
| | All MW | < 50% | 965 | 889 | 896 | 76 | 76 |
| | All MW | > 50% | 2,748 | 2,209 | 2,213 | 579 | 539 |
| Gas/Oil Steam (20) | All MW | All | 2,220 | 2,204 | 2,226 | 20 | 16 |
| | < 500 MW | All | 1,377 | 1,361 | 1,366 | 20 | 16 |
| | 500 MW – 1,000 MW | All | 488 | 488 | 489 | 0 | 0 |
| | > 1,000 MW | All | 355 | 355 | 355 | 0 | 0 |
| Gas/Oil Combined Cycle (30) | All MW | All | 1,367 | 980 | 981 | 408 | 387 |
| | < 500 MW | All | 764 | 462 | 463 | 304 | 302 |
| | 500 MW – 1,000 MW | All | 547 | 462 | 463 | 104 | 85 |
| | > 1,000 MW | All | 177 | 177 | 177 | 0 | 0 |
| | All MW | < 50% | 843 | 661 | 662 | 203 | 182 |
| | All MW | > 50% | 524 | 319 | 319 | 205 | 205 |
| Gas/Oil Combustion Turbine (40) | All MW | All | 5,041 | 4,905 | 4,949 | 437 | 136 |
| | < 100 MW | All | 2,873 | 2,873 | 2,911 | 189 | 0 |
| | 100 MW – 300 MW | All | 1,341 | 1,239 | 1,248 | 177 | 102 |
| | > 300 MW | All | 901 | 867 | 875 | 71 | 34 |
| Conventional Hydroelectric (50) | All MW | All | 2,179 | 2,179 | 2,180 | 0 | 0 |
| | < 100 MW | All | 1,272 | 1,272 | 1,272 | 0 | 0 |
| | 100 MW – 500 MW | All | 924 | 924 | 925 | 0 | 0 |
| | > 500 MW | All | 41 | 41 | 41 | 0 | 0 |

| Technology / (Dataset Identifier) | Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|---|
| | | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| Pumped Storage Hydroelectric (55) | All MW | All | 226 | 226 | 227 | 0 | 0 |
| | < 100 MW | All | 12 | 12 | 12 | 0 | 0 |
| | 100 MW – 500 MW | All | 88 | 88 | 88 | 0 | 0 |
| | > 500 MW | All | 126 | 126 | 126 | 0 | 0 |
| Solar Thermal (60) | | | 0 | | | | |
| Solar Photovoltaic (65) | All MW | All | 57 | 410 | 57 | 0 | 0 |
| Geothermal (70) | | | | | | | |
| Wind Turbine (80) | All MW | All | 310 | 310 | 310 | 270 | 0 |
| | < 100 MW | All | 174 | 174 | 174 | 165 | 0 |
| | 100 MW – 200 MW | All | 91 | 91 | 91 | 56 | 0 |
| | > 200 MW | All | 51 | 51 | 51 | 73 | 0 |

Note: A data point is one reported value for one year by one plant, i.e., a plant that reports values for 25 years will have 25 data points.

## 2.4 DATA NORMALIZATION

Sargent & Lundy developed a Microsoft Excel model template for compiling and normalizing all of the CAPEX and O&M data, subsequent to the initial review and validation steps outlined in the previous sections. The data normalization consisted of the following steps:

**Step 1:** Assign data "identifiers" for each plant:

Technology ID:

- 10 = Coal Steam Plants
- 20 = Gas/Oil Steam Plants
- 30 = Gas/Oil CC Plants
- 40 = Gas/Oil CTs
- 50 = Conventional Hydropower; Pumped Storage – Hydraulic Turbine Reversible
- 60 = Solar Thermal – Central Tower;
- 65 = Solar PV – Single-Axis Tracking
- 70 = Geothermal
- 80 = Wind

Data source:

- 1 = FERC Form 1
- 2 = Sargent & Lundy Internal Data
- 3 = Other Public Source

**Step 2:** Enter basic information for each plant:

- Year of commercial operation date (COD)
- End year of project life or forecast period
- Nameplate capacity (MW)
- Summer net capacity (MW)

**Step 3:** Adjust pricing basis for raw data:

- If provided in current dollars, adjust to 2017 dollars
- If provided in 2017 dollars, do not adjust
- If provided in constant dollars of another reference year, adjust to 2017 dollars

**Step 4:** Enter annual data for each plant (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant MW (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

Using the inputs from Steps 1-4 above, the “Normalizer” worksheet derives the following for each plant:

- Annual O&M in 2017 $/kW-year versus age (years from COD)
- Annual CAPEX in 2017 $/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

The output worksheets (“O&M,” “CAPEX,” and “O&M + CAPEX”) each have the following user-selected filters:

- Technology ID (10, 20, 30, etc.)

- Data source (1,2, or 3)
- MW range (low, high)
- Outlier maximum $/kW
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

Each output worksheet ("O&M," "CAPEX," and "O&M + CAPEX") calculates the following for a given user-defined set of filters:

- $/kW-year (2017 dollars) versus age
- Statistical tests of linear curve fit: annual spending in 2017 $/kW-year = $/kW-year (y-intercept) + [constant × age (years from COD)]
- Average $/kW-year (2017 dollars) for age bands (10-year bands, 30-year bands, and all-years band)

In all cases, the yearly values are expressed in constant 2017 price levels and increase annually with the inflation rate.

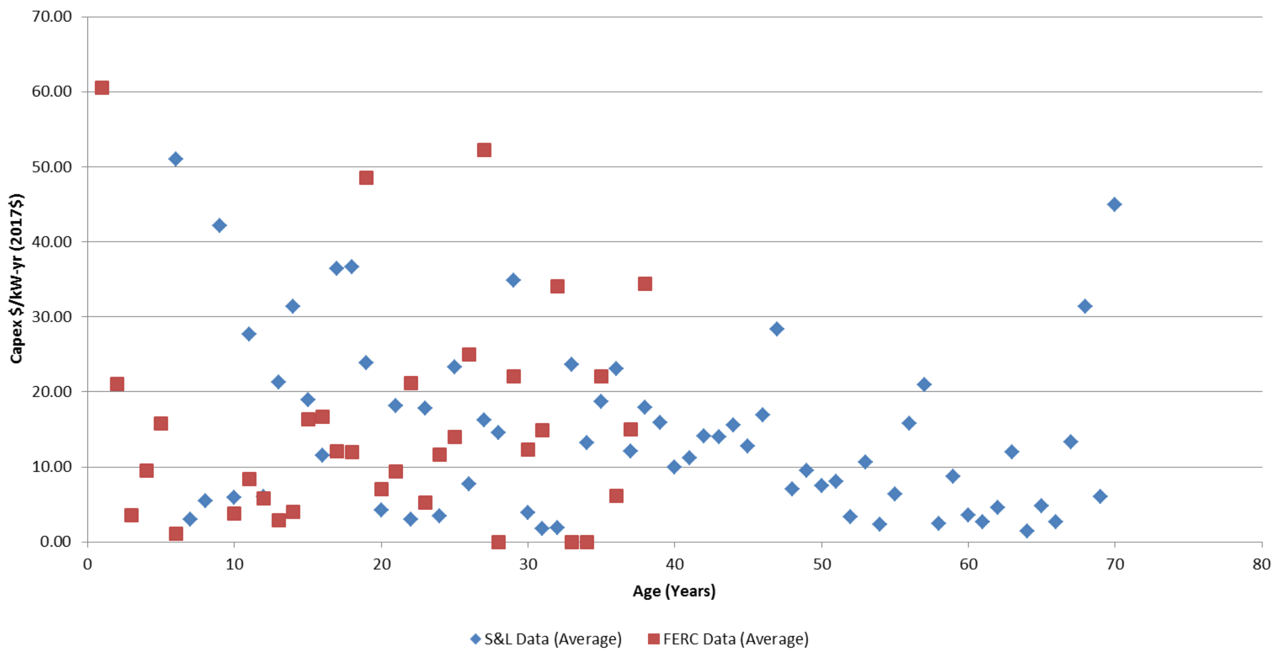
## 2.5 STATISTICAL TESTS

### 2.5.1 Consistency of FERC Form 1 and Sargent & Lundy Internal Data

FERC Form 1 data only covers historical data for utilities that are required to file and does not include the owners' projected expenditures or any data for merchant plants and independent power plants. Most of Sargent & Lundy's proprietary data, on the other hand, covers the owners' projected expenditures for utility plants and includes both historical and projected expenditures for merchant plants and independent power plants. The data points from both data sources were judged to be complementary and combined as a single dataset.

The compatibility of the FERC data and Sargent & Lundy internal data is illustrated by the CAPEX spending for a sample of 500-MW coal plants (Figure 2-1). This example is based on a sample of 11 plants from the Sargent & Lundy data and 12 plants from the FERC data, each sample having an average plant capacity of approximately 500 MW and an average age of approximately 30 years. Each data point in the figure is the average value for all the plants that have a valid data point at the given plant age. There are a total of 175 valid data points for the FERC plants and 200 valid data points for the Sargent & Lundy plants. In this particular sample, all of the FERC data is historical and all of the Sargent & Lundy data is owners' projected expenditures.

**Figure 2-1 — CAPEX vs. Age for 500-MW Coal Plants – FERC and Sargent & Lundy Data**



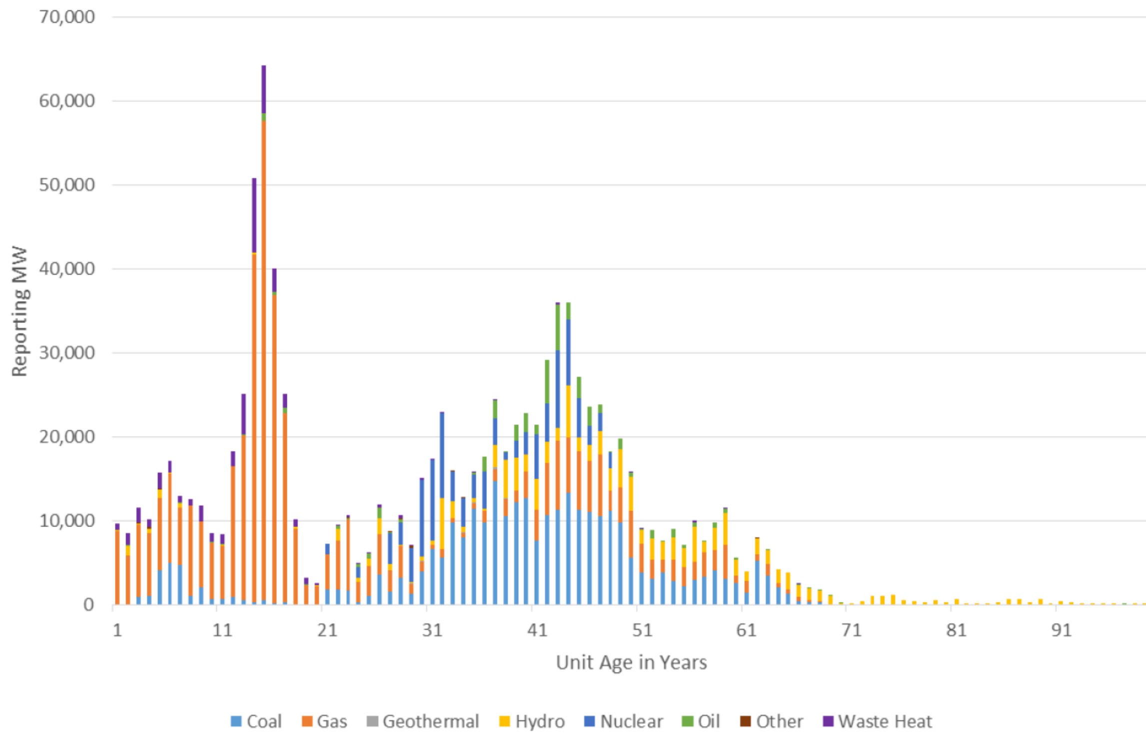

As discussed in Section 0, CAPEX spending for coal plants does not follow a uniform pattern for all plants. For example, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

For some utility plants, data was available from both FERC Form 1 and proprietary data. The historical O&M and CAPEX spending for these plants were examined in each year to verify their consistency.

The distribution of valid data points for each technology versus age (years from COD in which the spending occurs) was examined to verify consistency with typical plant ages nationwide. Figure 2-2 shows a recent distribution of the U.S. power plant fleet by unit age and fuel type as reported by FERC[8]. This distribution indicates a large portion of coal-fired capacity with ages of 30-50 years, and a large portion of gas-fired capacity (mostly CT or CC) with ages under 20 years. The valid data points assembled in this report were found to be representative of these major age and technology cohorts.

[8] North American Electric Reliability Corporation, *State of Reliability 2017*, June 2017 (p.116)

**Figure 2-2 — U.S. Power Plant Fleet Capacity by Age and Fuel Type**




A recent study found that the average age of the U.S. generator fleet has increased significantly over time, due in part to regulatory uncertainty in a deregulated market environment. At the same time, the average expected physical life of the fleet has been decreasing as a result of new investments in smaller, shorter-lived capacity. This has been a means of mitigating the regulatory risk of more limited stranded cost recovery mechanisms.[9] In another recent study, this one on the causes of power plant retirements, the strongest predictors of retirements were found to be $SO_2$ emission rates, planning reserve margins, variations in load growth or contraction, the age of older thermal plants, the ratio of coal to gas prices, and delivered natural gas prices. The impacts of annual CAPEX and O&M spending on retirement decisions were not specifically identified.[10]

### 2.5.2 Significance of Plant Age on Annual Capital and O&M Expenditures

For each technology group, Sargent & Lundy performed a regression analysis on the O&M spending, CAPEX spending, and combined O&M plus CAPEX spending using the following linear equation:

- Annual spending in 2017 $/kW-year = $/kW-year (y-intercept) + (constant × age)

[9] Rode, D., Fischbeck, P., and Paez, A., "Power Plant Lives and their Policy Implications," *Energy Policy*, 106 (2017) 222-232, April 1, 2017.
[10] Mills, A., Wiser, R., and Seel, J, "Power Plant Retirements: Trends and Possible Drivers," Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, November 2017.

The purpose of the regression analysis was to determine whether plant age is a statistically significant predictor of annual spending. The regression coefficient for age measures the change (+ or -) in annual spending as a function of plant age, measured as the number of years from the COD. Its statistical significance is measured by the p-value, which tests the null hypothesis that the coefficient is equal to zero (i.e., has no effect on spending).

The R-squared ($R^2$) statistic ("coefficient of determination") is an indication of the goodness of fit of the regression equation to the real data points. A low $R^2$ indicates that the regression equation explains a relatively small amount of the variability of the data around its mean. A low p-value (< 0.05) indicates that the age coefficient is statistically significant, regardless of the $R^2$ statistic. A low p-value corresponds approximately to a t-value that is greater than 2 or less than -2. For higher p-values, the simple average $/kW-year per year may be a more appropriate estimation for a given age band (e.g., 20-year bands and all-years band). Depending on the characteristics of the dataset, especially the number of data points, Sargent & Lundy applied engineering judgement (as further described in each section that follows) in our recommendations.

### 2.5.3 Autocorrelation of Time Series Data

In addition to the correlation between annual spending and plant age, an autocorrelation may also exist between spending in a given year and spending in previous years. Autocorrelation commonly occurs with time series data. If statistical tests verify the presence of autocorrelation, a lagged (autoregressive) variable may be added to improve the goodness of fit ($R^2$) of the regression model. Models with this functional form are referred to as "autoregressive integrated moving average" (ARIMA) models.

ARIMA models are typically constructed for the purpose of predicting the future from a given point in time, based on correlations with historical values and other exogenous variables. The functional form of an ARIMA model may better capture curvilinear or cyclical data trends and therefore improve the goodness of fit. For the purposes of this study, an ARIMA model was not necessary or appropriate. The datasets in this analysis already capture plant O&M and CAPEX spending patterns throughout a typical plant lifespan. The purpose of this study was to represent costs for generators as they age, and not to predict future spending from a given point in time.

# 3. COAL STEAM

## 3.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for coal steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M expenditures:
  - 456 plants in FERC data and 32 plants from Sargent & Lundy internal data
  - 3,098 valid data points in FERC data, 655 valid data points in Sargent & Lundy internal data
- CAPEX:
  - 457 plants in FERC data and 29 plants from Sargent & Lundy internal data
  - 3,109 valid data points in FERC data, 615 valid data points in Sargent & Lundy internal data

The coal steam data was broken down by plant MW capacity and average capacity factor—as summarized in Table 3-1—for the regression analysis shown in Appendix A.

**Table 3-1 — Coal Steam Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 3,713 | 3,098 | 3,109 | 655 | 615 |
| < 500 MW | All | 1,592 | 1,274 | 1,284 | 318 | 318 |
| 500 MW – 1,000 MW | All | 986 | 689 | 689 | 337 | 297 |
| 1,000 MW – 2,000 MW | All | 813 | 813 | 814 | 0 | 0 |
| > 2,000 MW | All | 322 | 322 | 322 | 0 | 0 |
| All MW | < 50% | 965 | 889 | 896 | 76 | 76 |
| All MW | > 50% | 2,748 | 2,209 | 2,213 | 579 | 539 |

Table 3-2 below identifies the relative effects in the data validation process of the top three data filters on the number of valid data points. These filters are described as follows:

- Change in Capacity: A change in nameplate capacity of 20% or more during the reported time of the unit. Data points prior to the change in capacity are no longer comparable to the data points after the change in capacity, so the entire unit was filtered out.
- Negative Change in Total Cost: Any year with a decrease in the cumulative historical capital cost reported in the FERC data was not included.
- Environmental Retrofit: Data points in years where $SO_2$, $NO_X$, PM, or Hg removal equipment was installed were filtered out.

**Table 3-2 — Effect of Data Validation Filters on Coal Data Points**

| Coal Steam – FERC Dataset | Data Points |
|---|---|
| Total Data Points, Unfiltered | 6,699 |
| Total Data Points, Filtered Out | 3,774 |
| **Top Three Filters** | |
| Change in Capacity | 1,659 |
| Negative Change in Total Cost | 889 |
| Environmental Retrofit | 599 |
| **Total Data Points, Valid (FERC Only)** | **2,925** |

## 3.2 SUMMARY OF RESULTS

### 3.2.1 Recommended CAPEX Values

The analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): age and flue gas desulfurization (FGD). Variables not having a significant effect on annual changes in real CAPEX spending (on a constant $/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 3-3 below compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

**Table 3-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors**

| Net Total CAPEX (2017 $/kW-year) | $/kW-yr (Years 1-10) | $/kW-yr (Years 10-20) | $/kW-yr (Years 20-30) | $/kW-yr (Years 30-40) | $/kW-yr (Years 40-50) | $/kW-yr (Years 50-60) | $/kW-yr (Years 60-70) | $/kW-yr (Years 70-80) |
|---|---|---|---|---|---|---|---|---|
| New Value – No FGD* | 17.16 | 18.42 | 19.68 | 20.94 | 22.20 | 23.46 | 24.72 | 25.98 |
| New Value – with FGD* | 22.84 | 24.10 | 25.36 | 26.62 | 27.88 | 29.14 | 30.40 | 31.66 |
| Existing EMM Value | 17.55 | 17.55 | 17.55 | 24.62 | 24.62 | 24.62 | 24.62 | 24.62 |

*Calculated from the following regression equation to the midpoint of the given age band:

**Annual CAPEX spending in 2017 $/kW-year = 16.53 + (0.126 × age) + (5.68 × FGD)**
**Where FGD = 1 if a plant has FGD; zero otherwise**

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently compared with plants without FGD.

Table 3-4 below provides indicative typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant.

**Table 3-4 — Coal Plant Indicative Typical CAPEX Projects and Intervals**

| Project Description | Typical Frequency of Repairs/Replacement from COD (Years) |
|---|---|
| **Boiler** | |
| Coal mills and exhausters, burner tips and ignitors | 5 |
| Lower nose tube, burner panels, economizer banks, air heater tubes, and baskets | 15 |
| Lower and upper waterwalls, superheater and reheater horizontal sections and pendants, economizer header, coal feeders, mill motors | 20 |
| Superheater and reheater header, feedwater supply piping | 25 |
| Mud and steam drums | 30 |
| **Turbine and Generator** | |
| Control valves, nozzle block | 12 |
| Electro-hydraulic control system (EHC), governor, turbine controls, generator rotor, turbine lubrication pumps | 15 |
| Stop valves, low-pressure (LP) turbine and blades, LP casing/diaphragms, | 20 |
| Steam chest, high-pressure/intermediate-pressure (HP/IP) turbine with blades, HP/IP casing/diaphragm, generator stator, exciter | 25 |
| HP/IP rotor, LP rotor, isophase | 30 |
| **Balance of Plant** | |
| Condensate pumps, cooling tower fill, cooling tower fan drives and blades, conveyor belts, conveyer idlers/pulleys/motors, coal crushing equipment | 10 |
| Slag conveyors and tanks | 12 |
| Induced draft (ID) fans, electrostatic precipitator (ESP) casing, ESP plates/wires, deaerator, circulating water pumps, boiler feed pumps, distributed control system (DCS)/unit controls, boiler master/combustion controls, coal handling dust control system | 15 |
| Forced draft (FD) fans, primary air (PA) fans, fan motors, windbox and ductwork, ESP transformer/rectifier (TR) sets and rappers, condenser valves and cleaner system, LP feedwater heaters, HP feedwater heaters, gland coolers, conveyor structures, coal unloading equipment, fuel oil heaters, and delivery pumps | 20 |
| Condenser retube, deaerator storage tank, vacuum pumps/steam air ejectors, pump motors | 25 |
| Main power transformer, auxiliary transformer | 30 |

### 3.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in \$/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in \$/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in \$/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary \$/MWh variable O&M breakout (Table 3-5).

**Table 3-5 — Coal Steam O&M Comparison with Existing EMM**

| | Fixed O&M (2017 \$/kW-yr) | Variable O&M (2017 \$/MWh)* | Variable O&M (2017 \$/kW-yr)** | Total O&M (2017 \$/kW-yr)** |
|---|---|---|---|---|
| Coal Steam Dataset Results – All Plants | 36.81 | 1.78 | 9.20 | 46.01 |
| < 500 MW | 44.21 | 1.78 | 9.20 | 53.41 |
| 500 MW – 1,000 MW | 34.02 | 1.78 | 9.20 | 43.22 |
| 1,000 MW – 2,000 MW | 28.52 | 1.78 | 9.20 | 37.72 |
| > 2,000 MW | 33.27 | 1.78 | 9.20 | 42.47 |
| Existing EMM Value*** | 40.63 | 1.78 | 9.20 | 49.83 |

*Fixed and variable split is estimated using the existing EMM variable O&M cost of \$1.78/MWh.
**Calculated at the coal steam dataset average capacity factor of 59%.
***Source: Internal communication with EIA, February 2018.

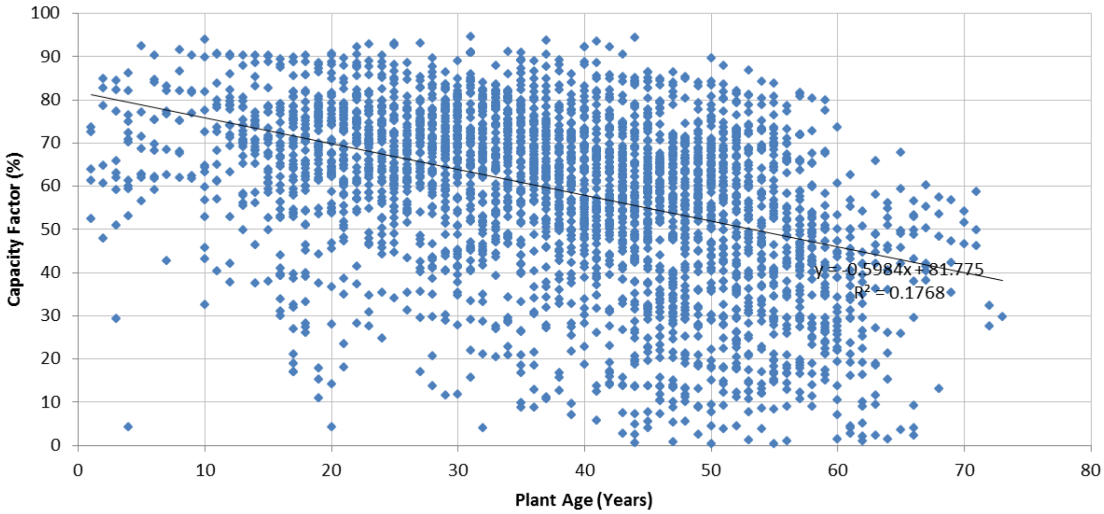
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

### 3.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a \$/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 3-1.

**Figure 3-1 — Capacity Factor vs. Age for All Coal Plants**




### 3.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.[11]

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam plants would likely retire under the following circumstances:

[11] Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table 3-6 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

**Table 3-6 — High Capacity Factor Coal Plants – Spending Comparison**

| | Average – All Years | Years 1-20 | Years 20-40 | Years 40-80 |
|---|---|---|---|---|
| Capacity Factor – All Plants | 59.1% | 66.8% | 64.5% | 52.9% |
| Capacity Factor – High CF Plants | 74.0% | - | 72.8% | 74.4% |
| O&M – All Plants (2017 $/kW-yr) | 46.01 | 53.90 | 40.06 | 48.77 |
| CAPEX – All Plants (2017 $/kW-yr) | 22.78 | 17.92 | 26.20 | 21.25 |
| Total – All Plants (2017 $/kW-yr) | 68.67 | 71.86 | 66.25 | 69.82 |
| O&M – High CF Plants (2017 $/kW-yr) | 36.65 | - | 31.07 | 38.78 |
| CAPEX – High CF Plants (2017 $/kW-yr) | 20.26 | - | 23.13 | 19.16 |
| Total – High CF Plants (2017 $/kW-yr) | 57.02 | - | 54.20 | 58.10 |

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

### 3.2.5 Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states (see Appendix A). Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

### 3.2.6 Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types (Appendix A). The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

# 4. GAS/OIL STEAM

## 4.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 283 plants in FERC data and four plants from Sargent & Lundy internal data
  - 2,204 valid data points in FERC data, 20 valid data points in Sargent & Lundy internal data
- CAPEX
  - 283 plants in FERC data and four plants from Sargent & Lundy internal data
  - 2,226 valid data points in FERC data, 16 valid data points in Sargent & Lundy internal data

The gas/oil steam data was broken down by plant MW capacity, as summarized below in Table 4-1, for the regression analysis shown in Appendix B.

**Table 4-1 — Gas/Oil Steam Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 2,220 | 2,204 | 2,226 | 20 | 16 |
| < 500 MW | All | 1,377 | 1,361 | 1,366 | 20 | 16 |
| 500 MW – 1,000 MW | All | 488 | 488 | 489 | 0 | 0 |
| > 1,000 MW | All | 355 | 355 | 355 | 0 | 0 |

## 4.2 SUMMARY OF RESULTS

### 4.2.1 Recommended CAPEX Values

Sargent & Lundy's analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 4-2 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

**Table 4-2 — Gas/Oil Steam CAPEX Results**

| Plant Size | Net Total CAPEX (2017 $/kW-year) | |
|---|---|---|
| | Years 1-30 | Years 30-80 |
| Gas/Oil Steam Dataset Results – All Plants | 15.96 | 15.96 |
| New Value: < 500 MW | 18.86 | 18.86 |
| New Value: 500 MW – 1,000 MW | 11.57 | 11.57 |
| New Value: > 1,000 MW | 10.82 | 10.82 |
| Existing EMM Value | 9.14 | 16.21 |

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair. Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRAs are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

### 4.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table 4-3). However, the variable O&M of $8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of $1.78/MWh in the EMM used for the coal units.

**Table 4-3 — Gas/Oil Steam O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh)* | Variable O&M (2017 $/kW-yr)** | Total O&M (2017 $/kW-yr)** |
|---|---|---|---|---|
| Gas/Oil Steam Dataset Results – All Plants | 24.68 | 1.00 | 1.84 | 26.52 |
| < 500 MW | 29.73 | 1.00 | 1.84 | 31.57 |
| 500 MW – 1,000 MW | 17.98 | 1.00 | 1.84 | 19.82 |
| > 1,000 MW | 14.51 | 1.00 | 1.84 | 16.35 |
| Existing EMM Value*** | 19.68 | 8.23 | 15.14 | 34.82 |

*Fixed and variable split is estimated using an approximate value for variable O&M of $1.00/MWh based on confidential projects.
**Calculated at the gas/oil steam dataset average capacity factor of 21%.
***Source: Internal communication with EIA, February 2018.

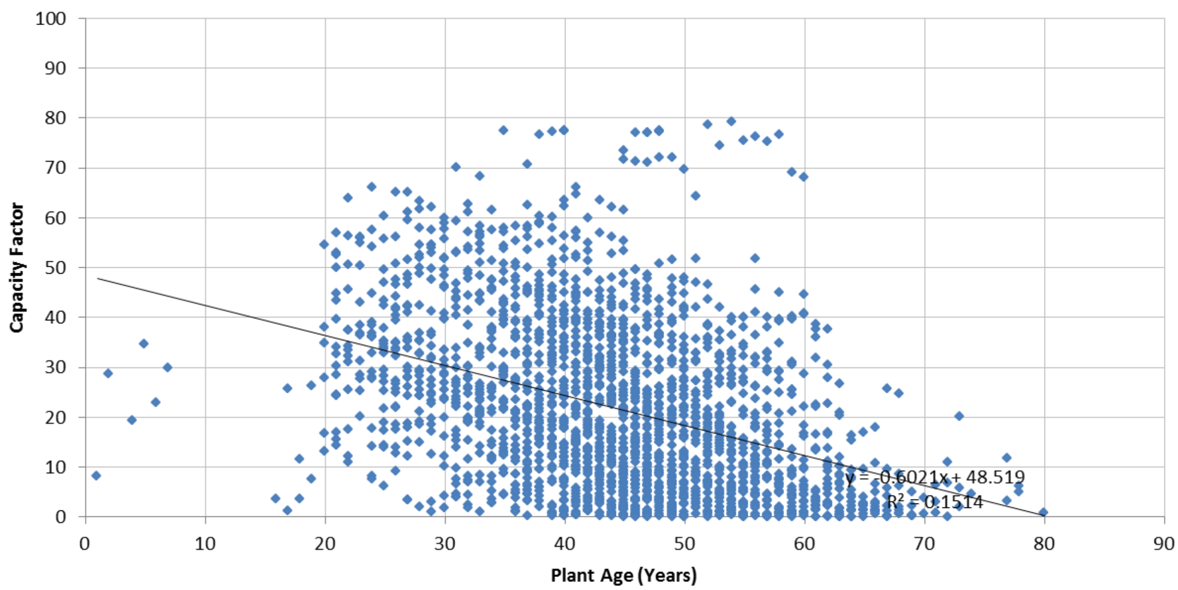
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

### 4.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the gas/oil steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 4-1.

**Figure 4-1 — Capacity Factor vs. Age for All Gas/Oil Steam Plants**




### 4.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for gas/oil steam plants include:

- Competition with more efficient gas turbines

- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

# 5. GAS/OIL COMBINED CYCLE

## 5.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CC plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 144 plants in FERC data and 20 plants from Sargent & Lundy internal data
  - 980 valid data points in FERC data, 408 valid data points in Sargent & Lundy internal data
- CAPEX
  - 142 plants in FERC data and 17 Sargent & Lundy proprietary plants with valid data
  - 981 valid data points in FERC data, 387 valid data points in Sargent & Lundy internal data

The gas/oil CC data was broken down by plant MW capacity and average capacity factor, as summarized below in Table 5-1, for the regression analysis shown in Appendix C.

**Table 5-1 — Gas/Oil CC Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 1,367 | 980 | 981 | 408 | 387 |
| < 500 MW | All | 764 | 462 | 463 | 304 | 302 |
| 500 MW – 1,000 MW | All | 547 | 462 | 463 | 104 | 85 |
| > 1,000 MW | All | 177 | 177 | 177 | 0 | 0 |
| All MW | < 50% | 843 | 661 | 662 | 203 | 182 |
| All MW | > 50% | 524 | 319 | 319 | 205 | 205 |

## 5.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC plants represents a series of capital projects throughout the plant life, which includes projects for “life extension.” Most CAPEX spending for gas/oil CC plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor’s recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table 5-2 compares the new CAPEX and O&M values derived from the gas/oil CC dataset with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the dataset would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of $7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the $/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

### Table 5-2 — Gas/Oil CC CAPEX and O&M Comparison with Existing EMM

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | Variable O&M (2017 $/kW-yr)* | Total O&M (2017 $/kW-yr)* | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr)* |
|---|---|---|---|---|---|---|
| CC Dataset Results – All Plants | 13.08 | 3.91 | (included in CAPEX) | 13.08 | 15.76 | 28.84 |
| < 500 MW | 15.62 | 4.31 | (included in CAPEX) | 15.62 | 17.38 | 33.00 |
| 500 MW – 1,000 MW | 9.27 | 3.42 | (included in CAPEX) | 9.27 | 13.78 | 23.05 |
| > 1,000 MW | 11.68 | 3.37 | (included in CAPEX) | 11.68 | 13.57 | 25.25 |
| Existing EMM Value** | 27.52 | 2.64 | 10.64 | 38.16 | 0.18; 7.25 (after year 30) | 38.34; 45.41 (after year 30) |

*Calculated at the gas/oil CC dataset average capacity factor of 46%. Fixed and variable O&M split is estimated.
**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

# 6. GAS/OIL COMBUSTION TURBINE

## 6.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CT plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 625 plants from FERC data and 27 plants from Sargent & Lundy internal data
  - 4,905 valid data points in FERC data, 437 valid data points in Sargent & Lundy internal data
- CAPEX
  - 579 plants from FERC data and five plants from Sargent & Lundy internal data
  - 4,949 valid data points in FERC data, 136 valid data points in Sargent & Lundy internal data

The CT data was broken down by plant MW capacity, as summarized below in Table 6-1, for the regression analysis shown in Appendix D.

**Table 6-1 — Gas/Oil Combustion Turbine Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 5,041 | 4,905 | 4,949 | 437 | 136 |
| < 100 MW | All | 2,873 | 2,873 | 2,911 | 189 | 0 |
| 100 MW – 300 MW | All | 1,341 | 1,239 | 1,248 | 177 | 102 |
| > 300 MW | All | 901 | 867 | 875 | 71 | 34 |

## 6.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CT plants represents a series of capital projects throughout the plant life, which includes projects for "life extension." Most CAPEX spending for gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CTs is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table 6-2 compares the new CAPEX and O&M values derived from the gas/oil CT datasets with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, EMM fixed and variable O&M costs across all plant sizes are higher than values Sargent & Lundy has observed in actual CT plants. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

**Table 6-2 — Gas/Oil Combustion Turbine CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | Variable O&M (2017 $/kW-yr)* | Total O&M (2017 $/kW-yr)* | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr)* |
|---|---|---|---|---|---|---|
| CT Dataset Results – All Plants | 5.33 | (starts based) | (included in CAPEX) | 5.33 | 6.90 | 12.23 |
| < 100 MW | 5.96 | (starts based) | (included in CAPEX) | 5.96 | 9.00 | 14.96 |
| 100 MW – 300 MW | 6.43 | (starts based) | (included in CAPEX) | 6.43 | 6.18 | 12.61 |
| > 300 MW | 3.99 | (starts based) | (included in CAPEX) | 3.99 | 6.95 | 10.94 |
| Existing EMM Value** | 12.60 | 14.63 | 5.13 | 17.73 | 1.52 | 19.25 |

*Calculated at the gas/oil CC dataset average capacity factor of 4%.
**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

# 7. CONVENTIONAL HYDROELECTRIC

## 7.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for conventional hydroelectric plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 348 plants in FERC data
  - 2,179 valid data points in FERC data
- CAPEX
  - 348 plants in FERC data
  - 2,180 valid data points in FERC data

The conventional hydroelectric data was broken down by plant MW capacity, as summarized below in Table 7-1, for the regression analysis shown in Appendix E.

**Table 7-1 — Conventional Hydroelectric Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 2,179 | 2,179 | 2,180 | 0 | 0 |
| < 100 MW | All | 1,272 | 1,272 | 1,272 | 0 | 0 |
| 100 MW – 500 MW | All | 924 | 924 | 925 | 0 | 0 |
| > 500 MW | All | 41 | 41 | 41 | 0 | 0 |

## 7.2 SUMMARY OF RESULTS

Sargent & Lundy's linear regression analysis of the dataset for conventional hydroelectric plants (Appendix E) supports age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). CAPEX spending for this dataset may be estimated by the regression equation:

**Annual CAPEX spending in 2017 $/kW-year = 7.269 + (0.296 × age)**

The dataset also supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 22.360 + (0.073 × age)**

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table 7-2) and outside the range of values published in the AEO[12] and by the International Renewable Energy Agency (IRENA).[13] The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

### Table 7-2 — Hydroelectric CAPEX and O&M Comparison with Existing EMM

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Conventional Hydroelectric Dataset Results – All Plants | 22.00 | - | 22.56 | 44.56 |
| Existing EMM Value* | 14.58 | 0.00 | 0.00 | 14.58 |

*Source: Internal communication with EIA, February 2018.

12 Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.
13 International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series*, *Hydropower*, June 2012.

# 8. PUMPED HYDROELECTRIC STORAGE

## 8.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for pumped storage plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 37 plants in FERC data
  - 226 valid data points in FERC data
- CAPEX
  - 37 plants in FERC data
  - 227 valid data points in FERC data

The pumped storage data was broken down by plant MW capacity, as summarized below in Table 8-1, for the regression analysis shown in Appendix F.

**Table 8-1 — Pumped Storage Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 226 | 226 | 227 | 0 | 0 |
| < 100 MW | All | 12 | 12 | 12 | 0 | 0 |
| 100 MW – 500 MW | All | 88 | 88 | 88 | 0 | 0 |
| > 500 MW | All | 126 | 126 | 126 | 0 | 0 |

## 8.2 SUMMARY OF RESULTS

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is \$14.83/kW-year for CAPEX and \$23.63/kW-year for O&M (Table 8-2). The existing values used in the EMM are not available.

**Table 8-2 — Pumped Storage CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Pumped Storage Dataset Results – All Plants | 23.63 | - | 14.83 | 38.46 |
| Existing EMM Value | N/A | N/A | N/A | N/A |

# 9. SOLAR PHOTOVOLTAIC

## 9.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for solar PV storage plants were compiled using the assessment methodology described in Section 2. The FERC data includes 105 solar PV installations ranging in capacity from 10 kW to 36 MW.

The solar PV data, summarized below in Table 9-1, was used for the regression analysis shown in Appendix G.

**Table 9-1 — Solar Photovoltaic Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 57 | 410 | 57 | 0 | 0 |

## 9.2 SUMMARY OF RESULTS

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size (see Appendix G). Sargent & Lundy determined that a significant portion of the data needed to be filtered out, resulting in a limited dataset of 15 sites. The average annual CAPEX (i.e., change in TCP) for these sites was approximately $26/kW-year. However, due to the limitations of the solar PV dataset, described in Appendix G, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based on a closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old and the fact that nearly all data points for plants over 10 years old are reported as having zero O&M expenses. Additionally, many of these plants also reported zero O&M expenses for all years of operation.

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment, inspecting modules for damage, inspecting mounting systems, and checking invertor settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

An average O&M cost of $75/kW-year was calculated from the FERC data for sites under 5 MW, and $15/kW-year for sites over 5 MW. Sargent & Lundy notes that, compared to other industry metrics shown in Appendix G, the FERC data averages are similar for the sites over 5 MW but much higher for the sites under 5 MW.

If the results of the regression analysis are used, the average O&M costs are reduced to $41/kW-year for sites under 5 MW and $10/kW-year for sites over 5 MW. The regression analysis uses each year of plant data as a unique data point, which captures the years in which zero O&M costs were reported.

By comparison, the EMM uses an average O&M value of $28.47/kW-year for all solar PV plants and an average CAPEX value of zero.[14] Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

[14] Internal communication with EIA, February 2018.

# 10. SOLAR THERMAL

## 10.1 DATA DESCRIPTION

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

## 10.2 SUMMARY OF RESULTS

The U.S. National Renewable Energy Laboratory (NREL) published an Annual Technology Baseline (ATB) in 2017 that estimates the capital and O&M cost of a 100-MWnet solar power tower plant with 10 hours of thermal storage, based on cost models benchmarked with industry data.[15] The estimate includes future projections based on possible reductions in costs (high, mid, or low). The 2017 ATB includes a 2015 baseline. An update is expected to be made available in 2018.

[15] NREL 2017 Annual Technology Baseline (https://atb.nrel.gov/electricity/2017/index.html?t=sc)

# 11. GEOTHERMAL

## 11.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for geothermal plants were compiled using the assessment methodology described in Section 2. The FERC data includes five geothermal installations ranging in capacity from 23 MW to 1,224 MW.

The geothermal data summarized in Table 11-1 was used for the regression analysis shown in Appendix I.

**Table 11-1 — Geothermal Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 36 | 38 | 36 | 0 | 0 |

## 11.2 SUMMARY OF RESULTS

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated $/kW-year average in Table 11-2 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

**Table 11-2 — Geothermal CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Geothermal Dataset Results – All Plants | 157.10 | - | 40.94 | 198.04 |
| Existing EMM Value* | 91.66 | 0.00 | 0.00 | 91.66 |

*Source: Internal communication with EIA, February 2018.

# 12. WIND

## 12.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for wind plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 73 plants in FERC and 24 from Sargent & Lundy proprietary plants with valid data
  - 310 valid data points in FERC, 270 valid data points in Sargent & Lundy proprietary plants
- CAPEX
  - 97 plants in FERC with valid data
  - 310 valid data points in FERC

Sargent & Lundy's dataset includes both actual historical cost reporting from operating wind projects as well as forecasted budgetary cost projections prepared by project developers and operators with large project portfolios.

Operating costs are assumed to include all expenses related to the maintenance of the wind project, such as planned and unplanned maintenance of the wind turbines and electrical balance of plant (including labor, parts, materials, and consumables) as well as operating expenses (such as facility monitoring and management fees, utilities, land lease and royalty payments, professional service fees, taxes, and insurance).

The wind data was broken down by plant MW capacity, as summarized below in Table 12-1, for the regression analysis shown in Appendix J.

**Table 12-1 — Wind Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 310 | 310 | 310 | 270 | 0 |
| < 100 MW | All | 174 | 174 | 174 | 165 | 0 |
| 100 MW – 200 MW | All | 91 | 91 | 91 | 56 | 0 |
| > 200 MW | All | 51 | 51 | 51 | 73 | 0 |

## 12.2 SUMMARY OF RESULTS

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table 12-2. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

**Table 12-2 — Wind CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) |
|---|---|---|---|
| Wind Dataset Results – All Plants | 31.66 + (1.22 × age) | 0.00 | 18.29 |
| < 100 MW | 39.08 + (1.12 × age) | 0.00 | 20.48 |
| 100 MW – 200 MW | 23.80 + (1.17 × age) | 0.00 | 16.93 |
| > 200 MW | 26.78 + (0.92 × age) | 0.00 | 13.48 |
| Existing EMM Value* | 29.31 | 0.00 | 0.00 |

*Source: Internal communication with EIA, February 2018.

# Appendix A. Regression Analysis – Coal Steam

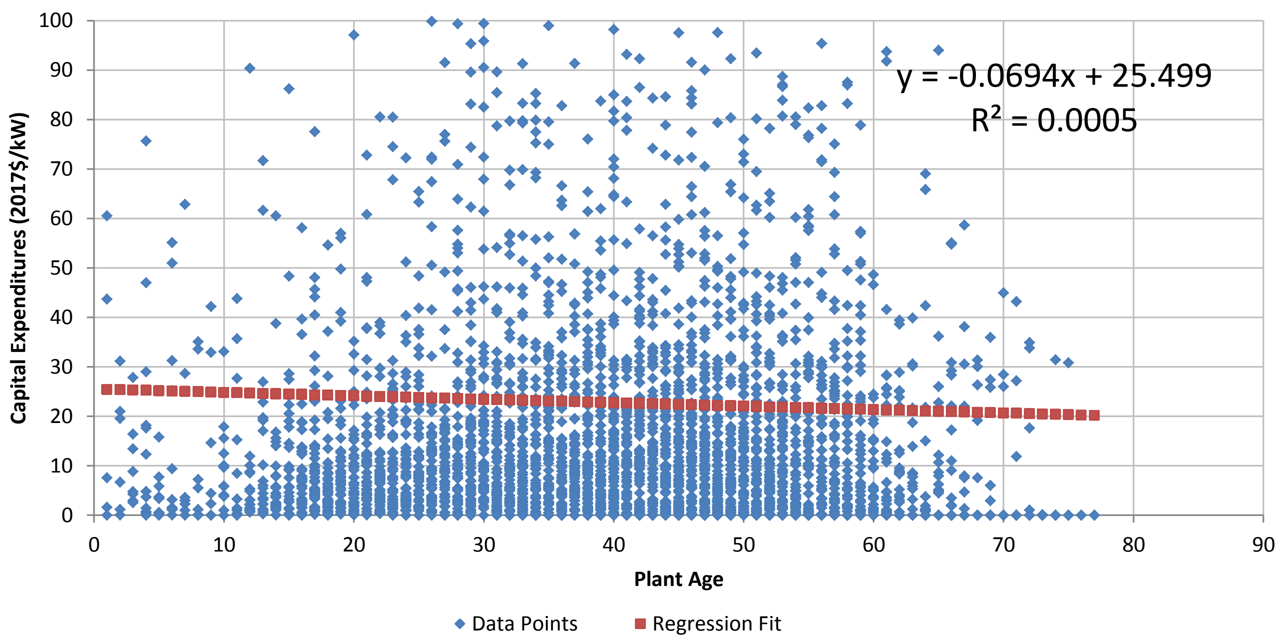
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.19, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, age and FGD are significant variables when an FGD variable is added to the regression equation (see below).

### Table A-1 — Regression Statistics – Coal CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 3,724 | | |
| **Simple Average ($/kW)** | 22.782 | | |
| **Intercept** | 25.499 | 11.4859 | 4.95E-30 |
| **Slope** | -0.069 | -1.3054 | 1.92E-01 |
| **$R^2$** | 0.00046 | | |

### Figure A-1 — Coal Steam Dataset – CAPEX for All MW Plant Sizes




Note: Age coefficient in above regression equation is not statistically significant.

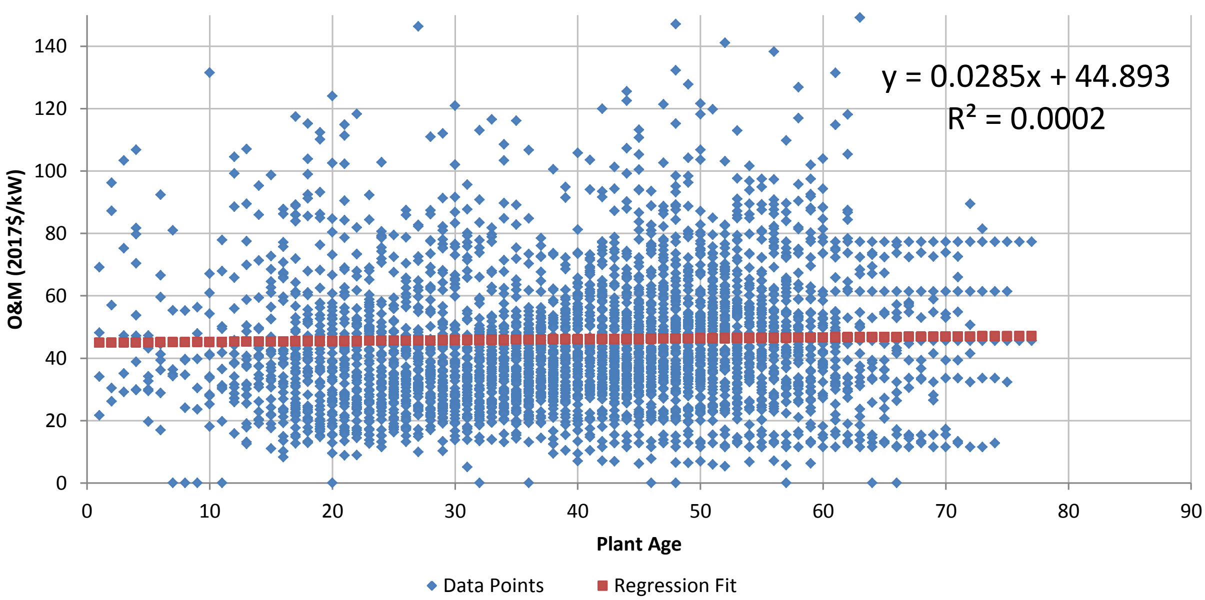
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.38, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

**Table A-2 — Regression Statistics – Coal O&M for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 3,753 | | |
| **Simple Average ($/kW)** | 46.013 | | |
| **Intercept** | 44.893 | 33.2097 | 3.08E-212 |
| **Slope** | 0.028 | 0.8843 | 3.77E-01 |
| **$R^2$** | 0.00021 | | |

**Figure A-2 — Coal Steam Dataset – O&M for All MW Plant Sizes**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 53.90 | 40.06 | 48.77 | **46.01** | 440 | 1,448 | 1,865 | **3,753** |
| Net Total Capex - 2017 $/kW | 17.92 | 26.20 | 21.25 | **22.78** | 441 | 1,450 | 1,833 | **3,724** |
| Net Total O&M and Capex - 2017 $/kW | 71.86 | 66.25 | 69.82 | **68.67** | 440 | 1,448 | 1,825 | **3,713** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

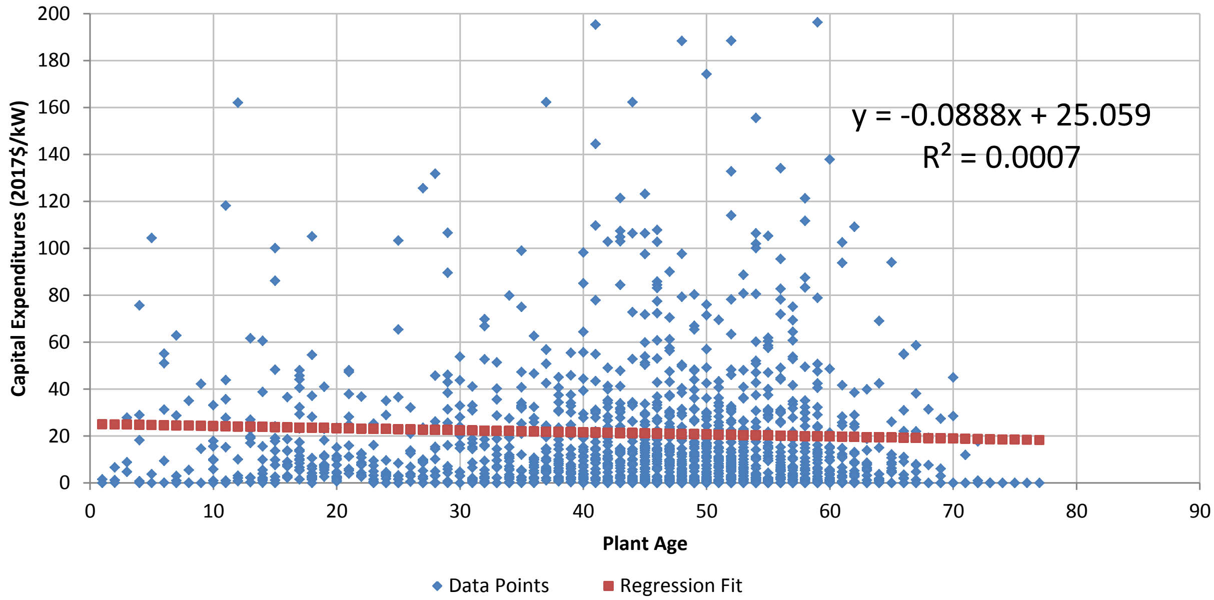
## CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.28, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table A-3 — Regression Statistics – Coal CAPEX < 500 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,602 | | |
| **Simple Average ($/kW)** | 21.187 | | |
| **Intercept** | 25.059 | 6.5593 | 7.28E-11 |
| **Slope** | -0.089 | -1.0685 | 2.85E-01 |
| **$R^2$** | 0.00071 | | |

### Figure A-3 — Coal Steam Dataset – CAPEX for Less than 500-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

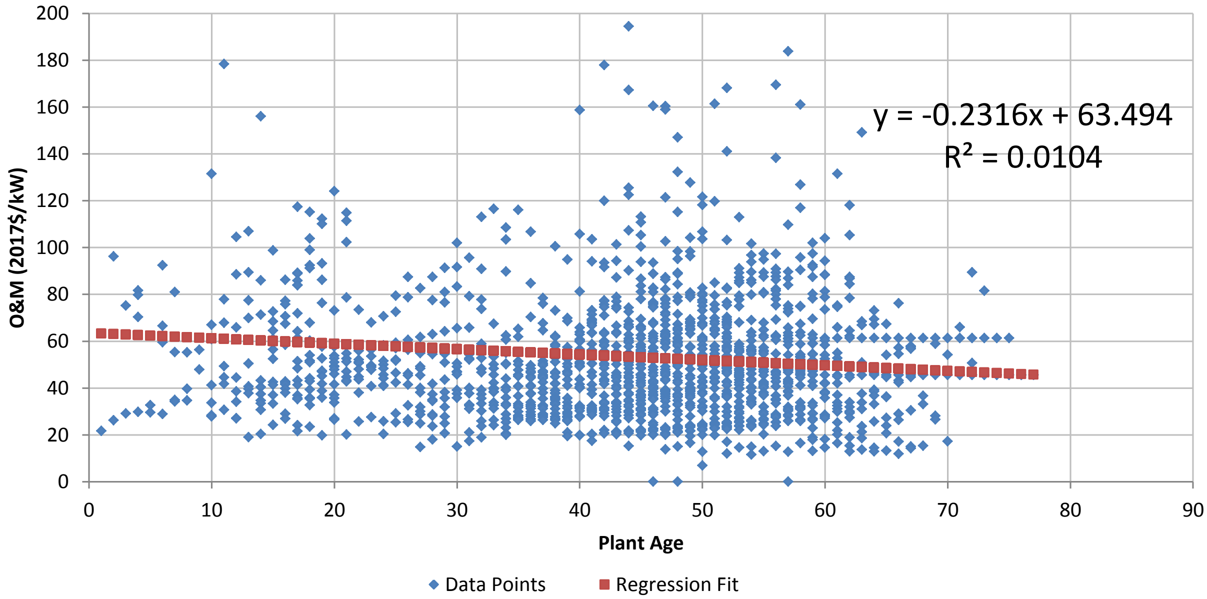
The results of the regression analysis of O&M spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the following regression equation:

**Annual spending in 2017 $/kW-year = 63.494 + (-0.232 × age)**

### Table A-4 — Regression Statistics – Coal O&M < 500 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,592 | | |
| **Simple Average ($/kW)** | 53.406 | | |
| **Intercept** | 63.494 | 24.4603 | 2.03E-112 |
| **Slope** | -0.232 | -4.0977 | 4.38E-05 |
| **$R^2$** | 0.01045 | | |

**Figure A-4 — Coal Steam Dataset – O&M for Less than 500-MW Plant Size**




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **< 500 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 68.13 | 47.13 | 53.16 | **53.41** | 169 | 355 | 1,068 | **1,592** |
| Net Total Capex - 2017 $/kW | 21.01 | 22.83 | 20.67 | **21.19** | 169 | 357 | 1,076 | **1,602** |
| Net Total O&M and Capex - 2017 $/kW | 89.14 | 69.91 | 73.93 | **74.65** | 169 | 355 | 1,068 | **1,592** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

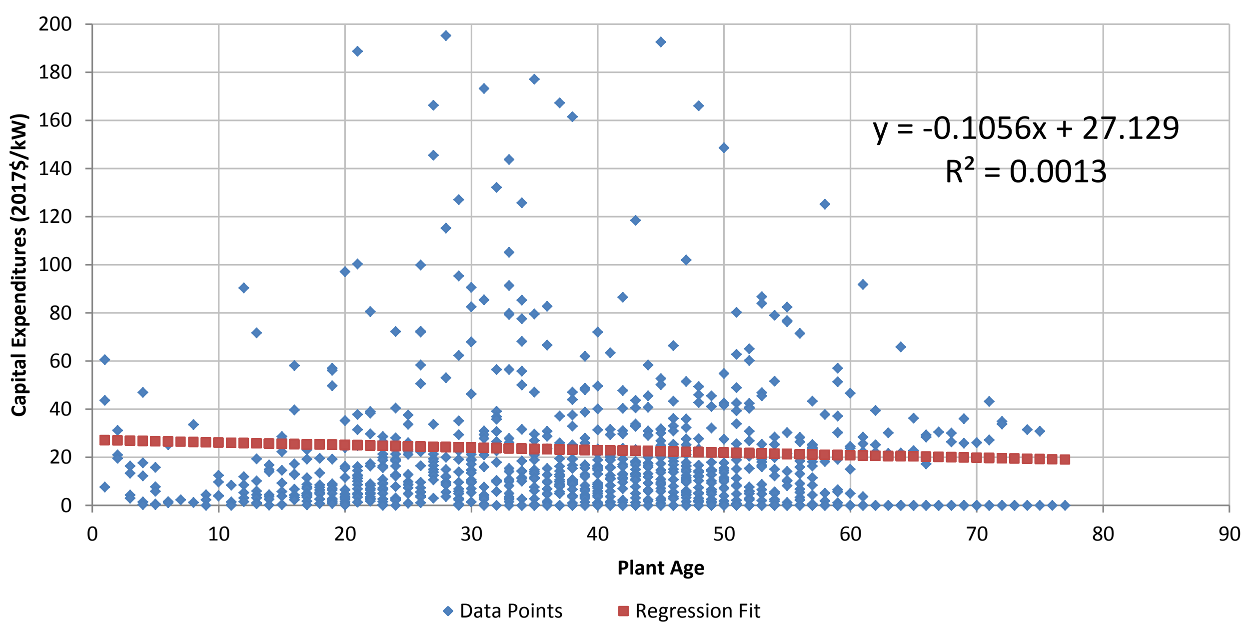
## CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.26, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

### Table A-5 — Regression Statistics – Coal CAPEX 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 986 | | |
| **Simple Average ($/kW)** | 23.021 | | |
| **Intercept** | 27.129 | 6.8576 | 1.24E-11 |
| **Slope** | -0.106 | -1.1195 | 2.63E-01 |
| **$R^2$** | 0.00127 | | |

### Figure A-5 — Coal Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

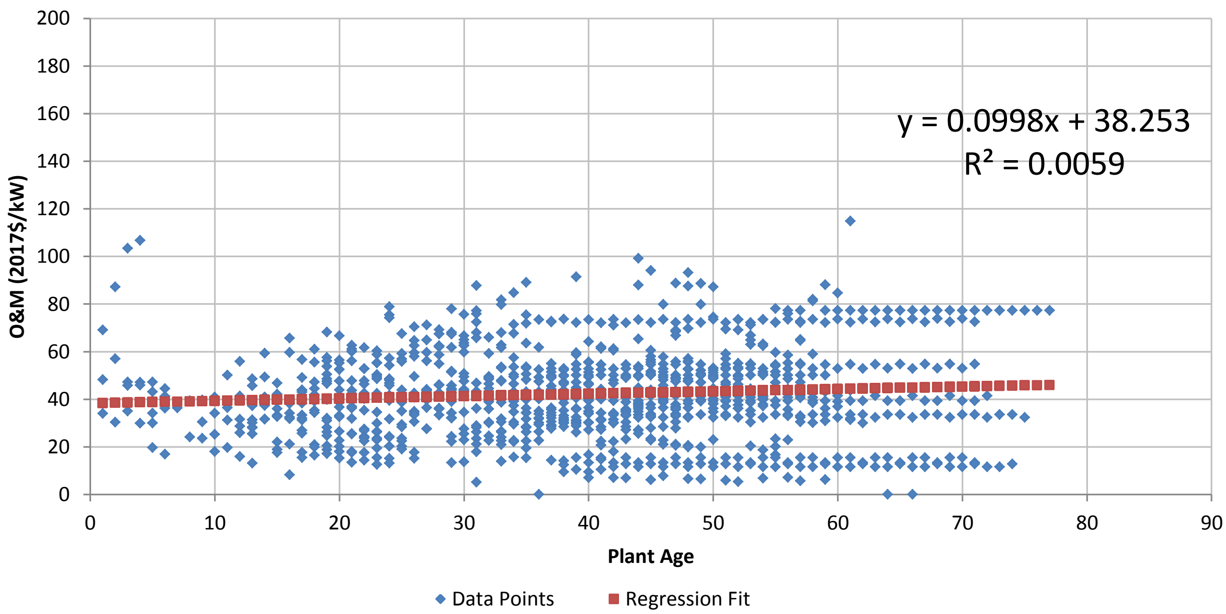
The results of the linear regression analysis of O&M spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual spending in 2017 $/kW-year = 38.253 + (0.100 × age)**

### Table A-6 — Regression Statistics – Coal O&M 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,026 | | |
| **Simple Average ($/kW)** | 42.223 | | |
| **Intercept** | 38.253 | 22.0915 | 9.54E-89 |
| **Slope** | 0.100 | 2.4710 | 1.36E-02 |
| **$R^2$** | 0.00593 | | |

### Figure A-6 — Coal Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **500 MW - 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 38.15 | 42.09 | 43.40 | **42.22** | 138 | 369 | 519 | **1,026** |
| Net Total Capex - 2017 $/kW | 12.27 | 32.63 | 18.71 | **23.02** | 138 | 369 | 479 | **986** |
| Net Total O&M and Capex - 2017 $/kW | 50.41 | 74.72 | 60.65 | **64.49** | 138 | 369 | 479 | **986** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

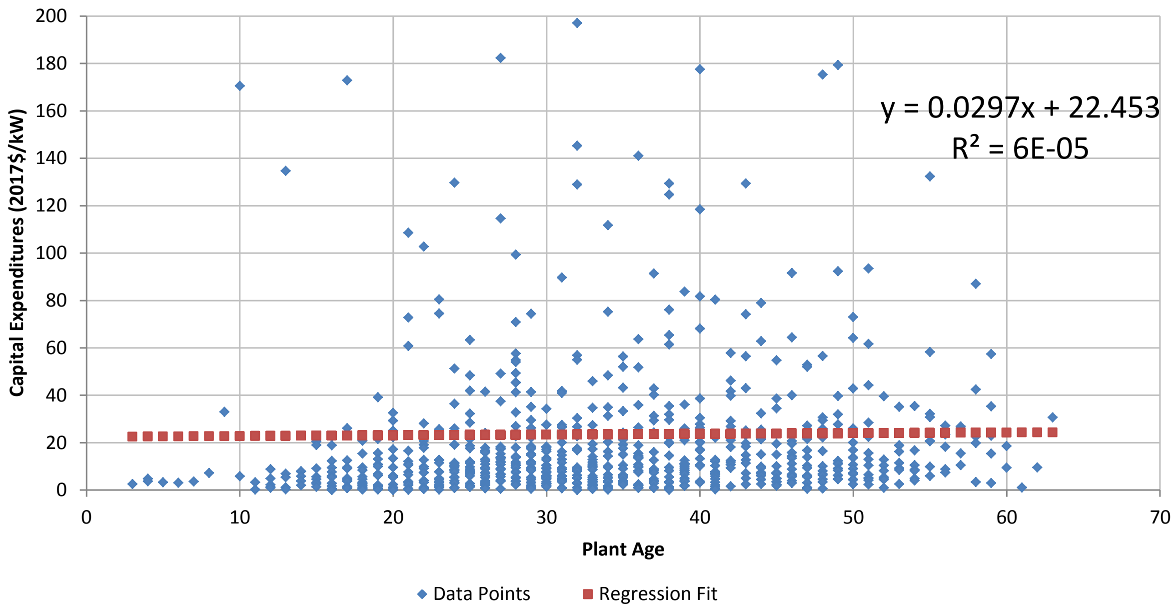
## CAPITAL EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.83, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

### Table A-7 — Regression Statistics – Coal CAPEX 1,000 MW to 2,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 814 | | |
| **Simple Average ($/kW)** | 23.448 | | |
| **Intercept** | 22.453 | 4.6325 | 4.21E-06 |
| **Slope** | 0.030 | 0.2174 | 8.28E-01 |
| **$R^2$** | 0.00006 | | |

### Figure A-7 — Coal Steam Dataset – CAPEX for 1,000-MW to 2,000-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

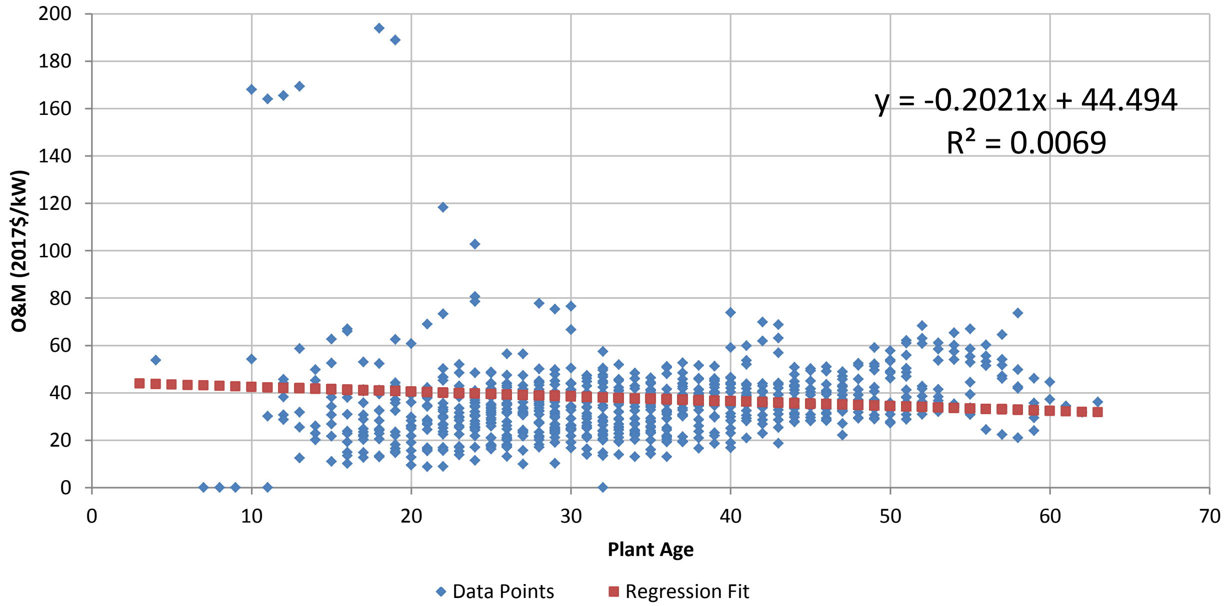
The results of the regression analysis of O&M spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

| **Annual spending in 2017 \$/kW-year = 44.494 + (-0.202 × age)** |
|---|

### Table A-8 — Regression Statistics – Coal O&M 1,000 MW to 2,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 813 | | |
| **Simple Average (\$/kW)** | 37.722 | | |
| **Intercept** | 44.494 | 14.7620 | 7.42E-44 |
| **Slope** | -0.202 | -2.3785 | 1.76E-02 |
| **$R^2$** | 0.00693 | | |

**Figure A-8 — Coal Steam Dataset – O&M for 1,000-MW to 2,000-MW Plant Size**




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **1000 MW - 2000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 53.51 | 32.80 | 40.62 | **37.72** | 107 | 478 | 228 | **813** |
| Net Total Capex - 2017 $/kW | 22.56 | 23.31 | 24.16 | **23.45** | 108 | 478 | 228 | **814** |
| Net Total O&M and Capex - 2017 $/kW | 76.28 | 56.11 | 64.78 | **61.20** | 107 | 478 | 228 | **813** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

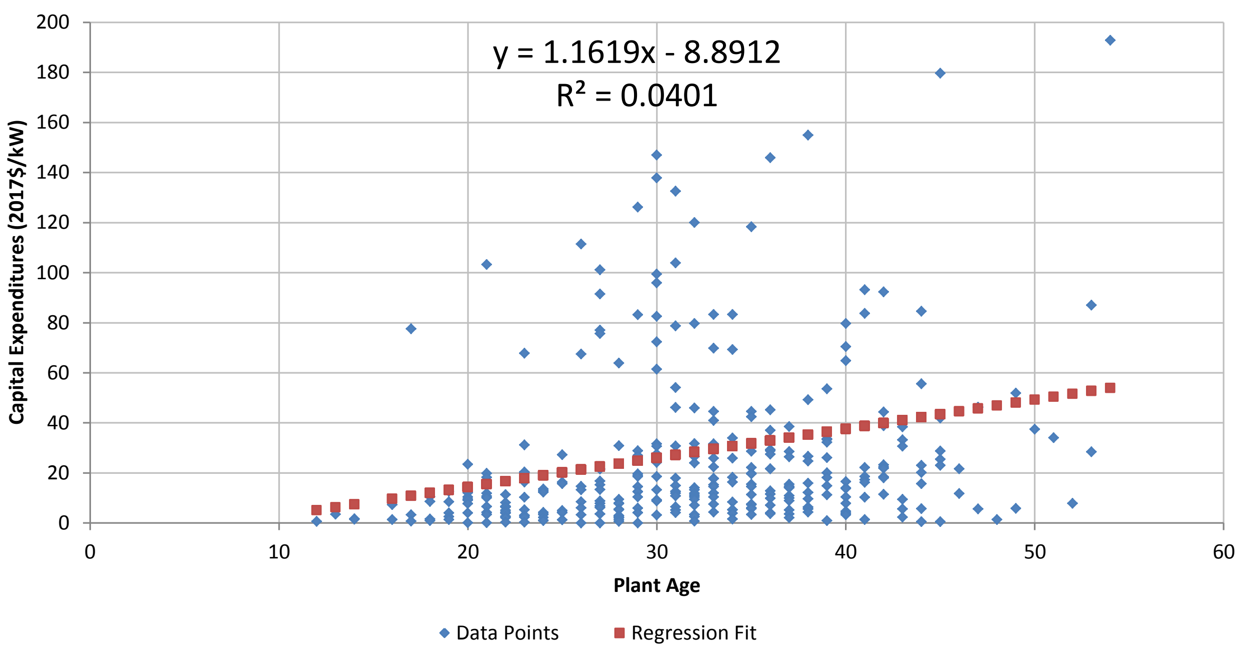
## CAPITAL EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the linear regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

### Table A-9 — Regression Statistics – Coal CAPEX > 2,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 322 | | |
| **Simple Average ($/kW)** | 28.303 | | |
| **Intercept** | -8.891 | -0.8468 | 3.98E-01 |
| **Slope** | 1.162 | 3.6556 | 3.00E-04 |
| **$R^2$** | 0.04009 | | |

### Figure A-9 — Coal Steam Dataset – CAPEX for Greater than 2,000-MW Plant Size



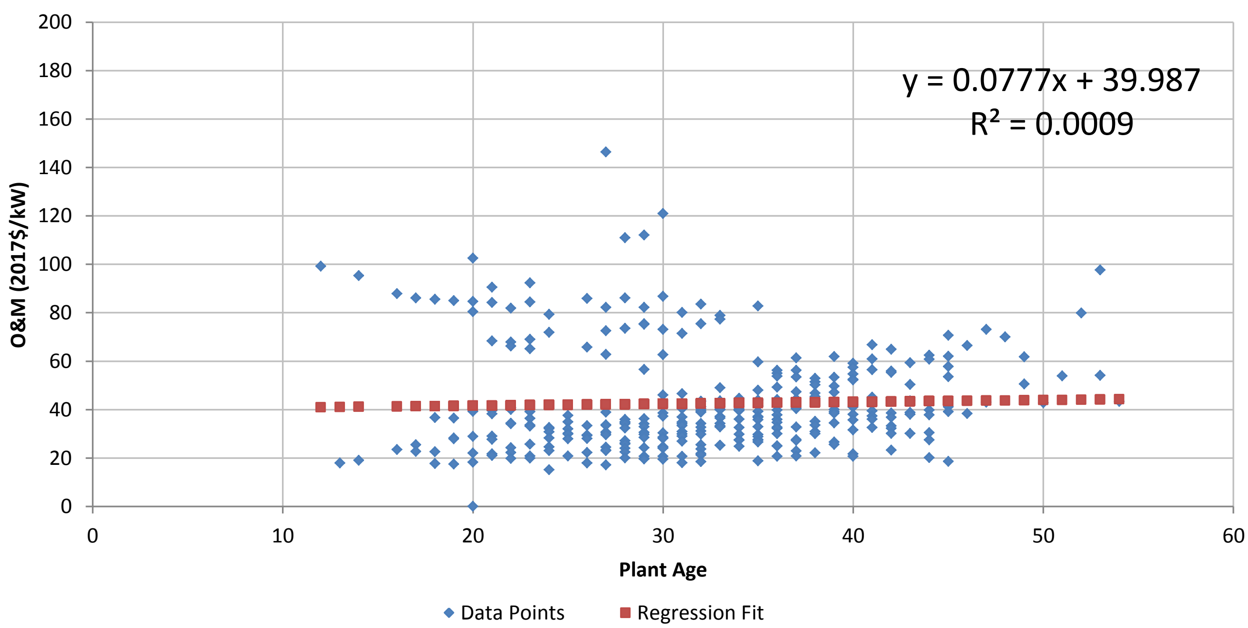
## OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of O&M spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.59, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

### Table A-10 — Regression Statistics – Coal O&M > 2,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 322 | | |
| **Simple Average ($/kW)** | 42.474 | | |
| **Intercept** | 39.987 | 8.3303 | 2.39E-15 |
| **Slope** | 0.078 | 0.5348 | 5.93E-01 |
| **$R^2$** | 0.00089 | | |

### Figure A-10 — Coal Steam Dataset – O&M for Greater than 2,000-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **> 2000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 46.55 | 40.91 | 48.04 | **42.47** | 26 | 246 | 50 | **322** |
| Net Total Capex - 2017 $/kW | 8.65 | 27.06 | 44.64 | **28.30** | 26 | 246 | 50 | **322** |
| Net Total O&M and Capex - 2017 $/kW | 55.20 | 67.97 | 92.67 | **70.78** | 26 | 246 | 50 | **322** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

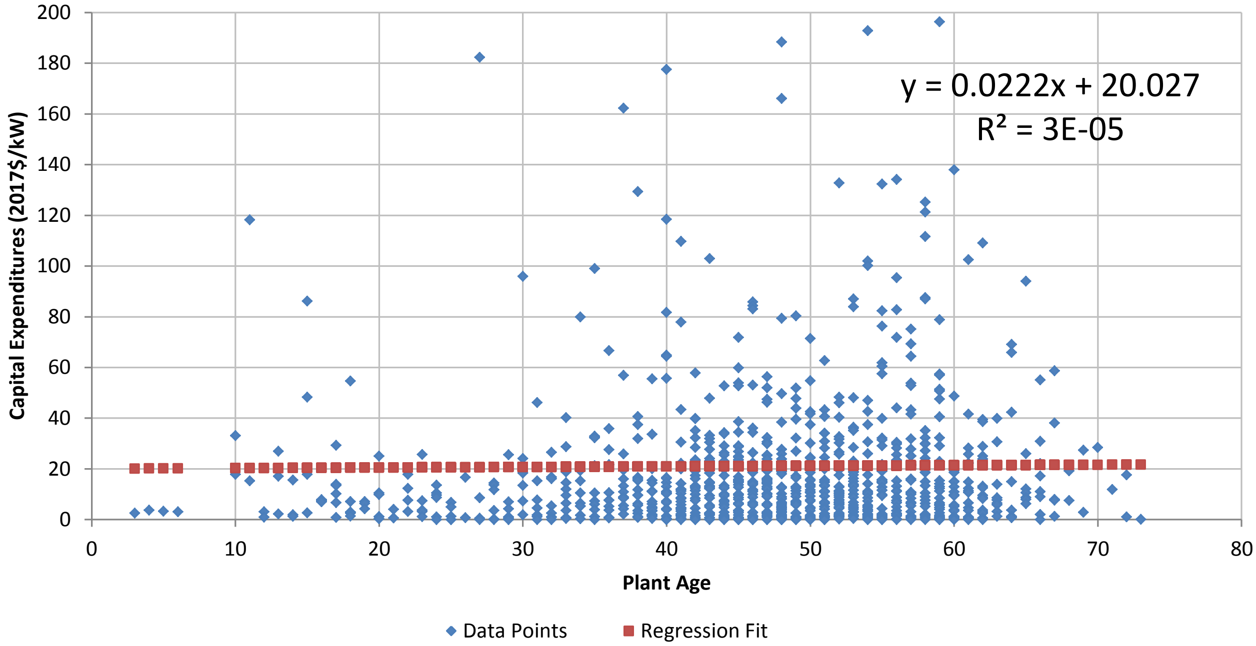
## CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.87, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table A-11 — Regression Statistics – Coal CAPEX for Capacity Factor < 50%

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 972 | | |
| **Simple Average ($/kW)** | 21.063 | | |
| **Intercept** | 20.027 | 3.1188 | 1.87E-03 |
| **Slope** | 0.022 | 0.1663 | 8.68E-01 |
| **$R^2$** | 0.00003 | | |

**Figure A-11 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor < 50%**




Note: Age coefficient in above regression equation is not statistically significant.

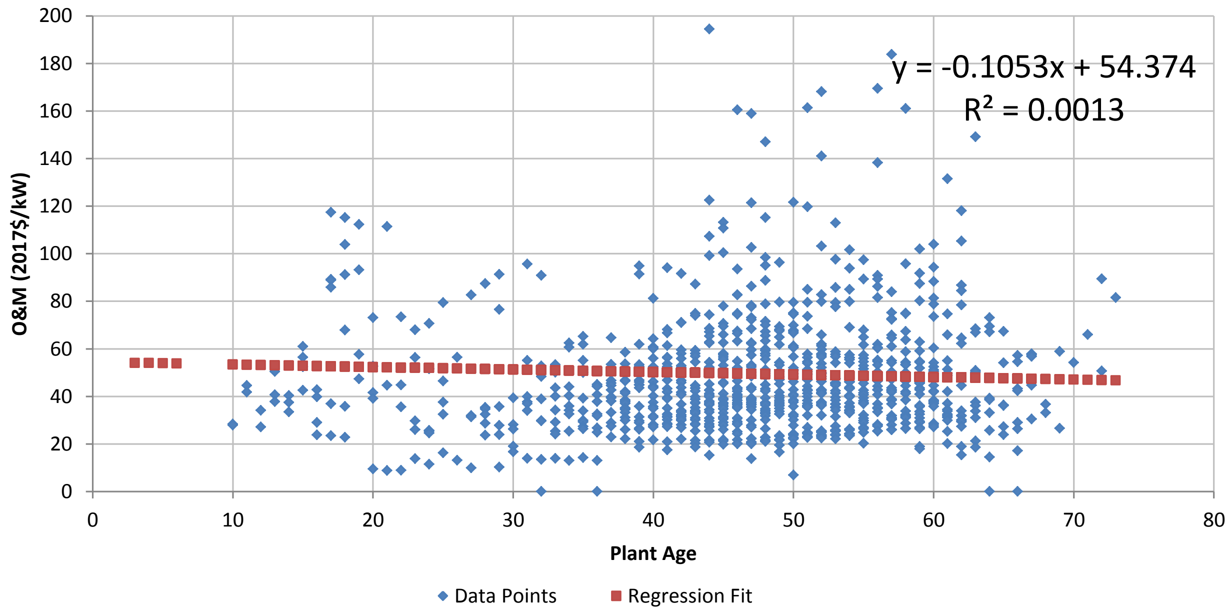
## OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.26, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

**Table A-12 — Regression Statistics – Coal O&M for Capacity Factor < 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 965 | | |
| **Simple Average ($/kW)** | 49.454 | | |
| **Intercept** | 54.374 | 12.0380 | 3.43E-31 |
| **Slope** | -0.105 | -1.1234 | 2.62E-01 |
| **$R^2$** | 0.00131 | | |

### Figure A-12 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor < 50%




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, Capacity Factors 0 - 50%** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 76.43 | 40.01 | 50.07 | **49.45** | 45 | 177 | 743 | **965** |
| Net Total Capex - 2017 $/kW | 19.62 | 23.74 | 20.51 | **21.06** | 45 | 179 | 748 | **972** |
| Net Total O&M and Capex - 2017 $/kW | 96.04 | 63.66 | 70.63 | **70.54** | 45 | 177 | 743 | **965** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

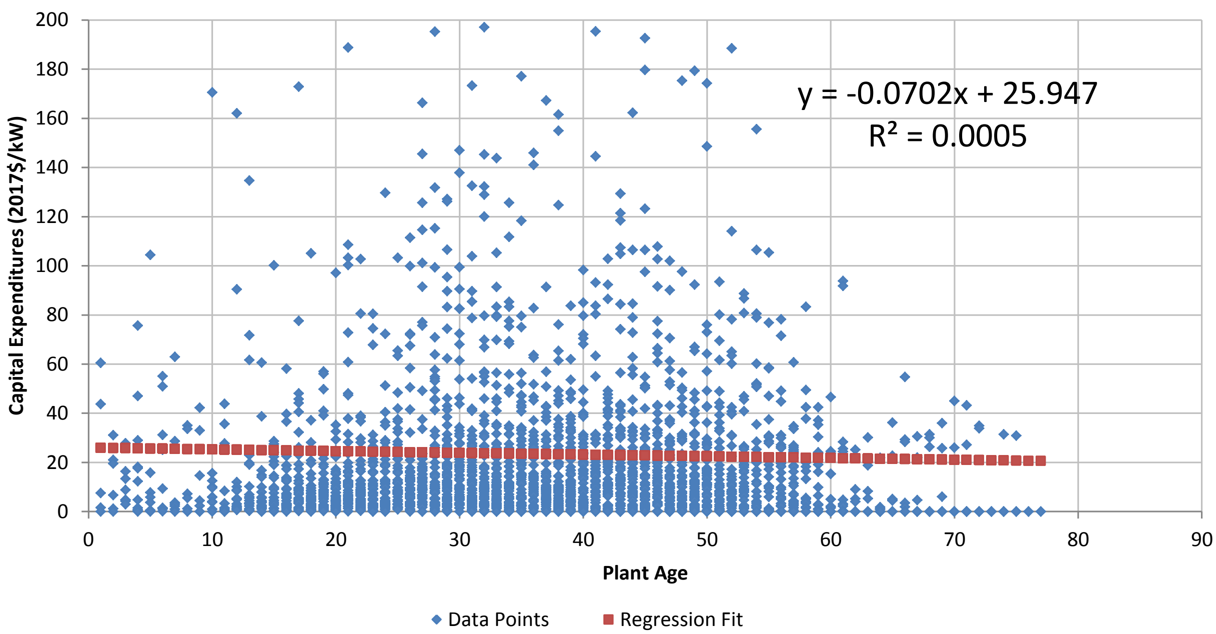
## CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.25, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table A-13 — Regression Statistics – Coal CAPEX for Capacity Factor > 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2752 | | |
| **Simple Average ($/kW)** | 23.389 | | |
| **Intercept** | 25.947 | 10.7905 | 1.29E-26 |
| **Slope** | -0.070 | -1.1446 | 2.52E-01 |
| **$R^2$** | 0.00048 | | |

**Figure A-13 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor > 50%**




Note: Age coefficient in above regression equation is not statistically significant.

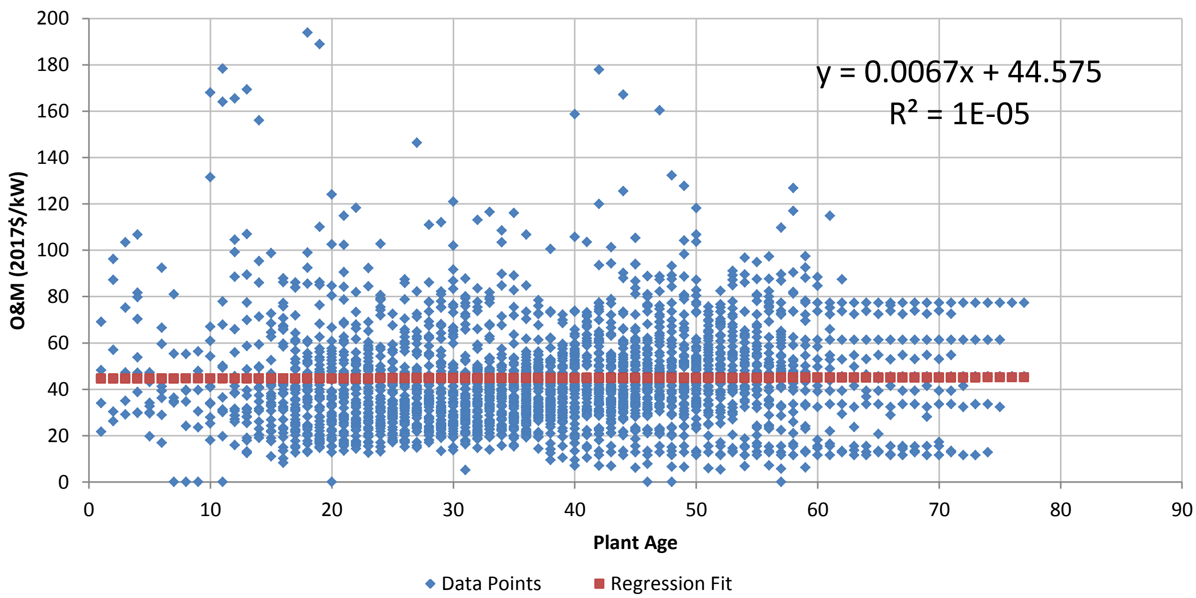
## OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.85, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

**Table A-14 — Regression Statistics – Coal O&M for Capacity Factor > 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2788 | | |
| **Simple Average ($/kW)** | 44.822 | | |
| **Intercept** | 44.575 | 32.6995 | 8.78E-199 |
| **Slope** | 0.007 | 0.1954 | 8.45E-01 |
| **$R^2$** | 0.00001 | | |

**Figure A-14 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor > 50%**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, Capacity Factors 50% - 100%** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 51.33 | 40.07 | 47.92 | **44.82** | 395 | 1,271 | 1,122 | **2,788** |
| Net Total Capex - 2017 $/kW | 17.73 | 26.55 | 21.75 | **23.39** | 396 | 1,271 | 1,085 | **2,752** |
| Net Total O&M and Capex - 2017 $/kW | 69.11 | 66.62 | 69.25 | **68.01** | 395 | 1,271 | 1,082 | **2,748** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

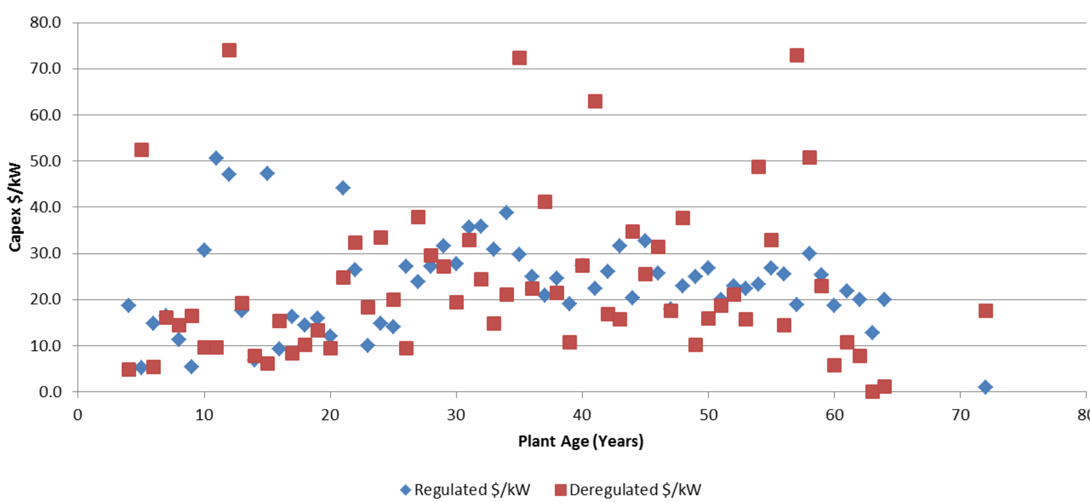
## CAPITAL EXPENDITURES – REGULATED VS. DEREGULATED

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in regulated versus deregulated locations are summarized in the table below. Since the p-value for the age ("slope") and regulation/deregulation coefficients are much greater than 0.05, age and regulatory status are not statistically significant predictors of CAPEX spending.

**Table A-15 — Regression Statistics – Coal CAPEX for Regulated/Deregulated**

| | Coefficients | Standard Error | t Stat | P-Value |
|---|---|---|---|---|
| Intercept | 23.22826383 | 2.9645403 | 7.835367875 | 6.36821E-15 |
| Age | 0.097334249 | 0.064355791 | 1.512439626 | 0.130523796 |
| Reg./Dereg. (1/0) | -2.479225741 | 2.148990587 | -1.153669893 | 0.248724297 |

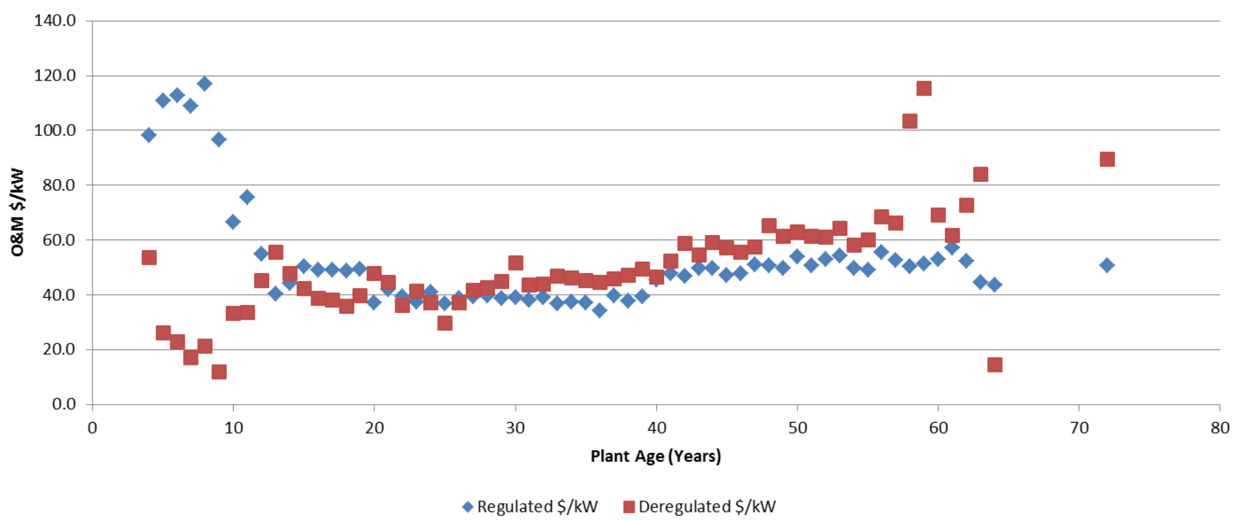
**Figure A-15 — Coal Steam Dataset – CAPEX for Regulated/Deregulated**



## OPERATIONS & MAINTENANCE EXPENDITURES – REGULATED VS. DEREGULATED

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and regulated/deregulated coefficients are much less than 0.05 (i.e., statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. After year 20, a visual inspection of the data points indicates higher O&M spending in deregulated states compared with regulated states (Figure A-16). This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending is not apparent at this level of detail.

**Figure A-16 — Coal Steam Dataset – O&M for Regulated vs. Deregulated**




## CAPITAL EXPENDITURES – FGD VS. NO FGD

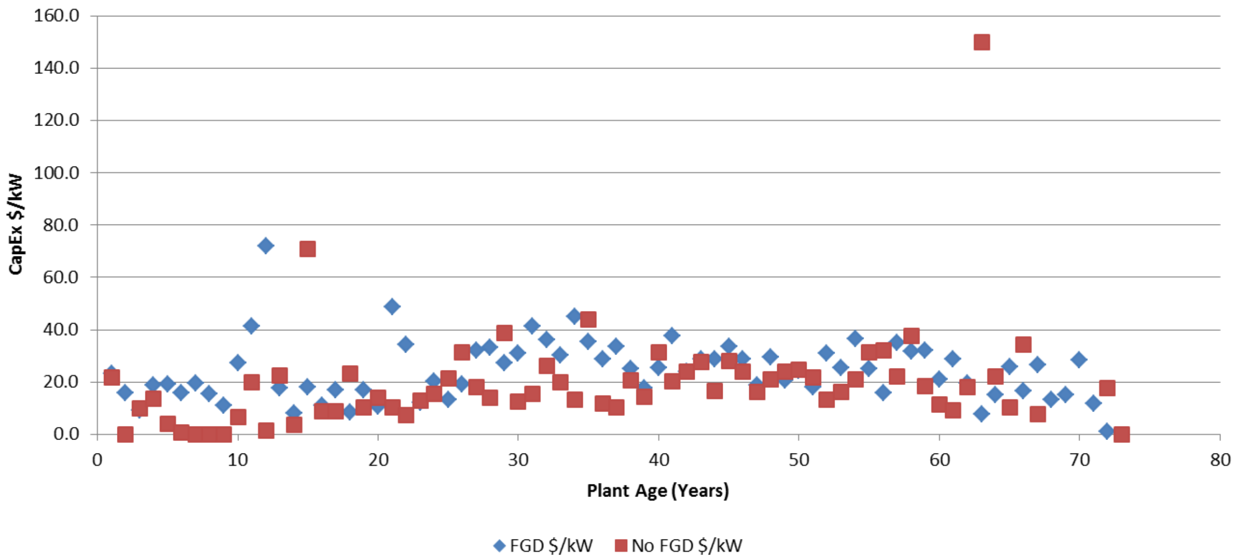
The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) with and without FGD are summarized in the table below. The p-value for the age ("slope") coefficient is slightly greater than 0.05 (nearly statistically significant) while the p-value for the FGD/no-FGD coefficient is much less than 0.05 (statistically significant). A visual inspection of the difference between the FGD and no-FGD data points in Figure A-17 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending may be represented by the following regression equation:

**Annual CAPEX spending in 2017 $/kW-year = 16.53 + (0.126 × age) + (5.68 × FGD)**
**Where FGD = 1 if plant has FGD; zero otherwise**

**Table A-16 — Regression Statistics – Coal CAPEX for FGD/No FGD**

| | Coefficients | Standard Error | t Stat | P-Value |
|---|---|---|---|---|
| Intercept | 16.52586075 | 3.06139723 | 5.39814323 | 7.2399E-08 |
| Age | 0.126266024 | 0.065143952 | 1.93826166 | 0.05268181 |
| FGD/No FGD (1/0) | 5.6788887 | 1.913609818 | 2.96763146 | 0.00302395 |

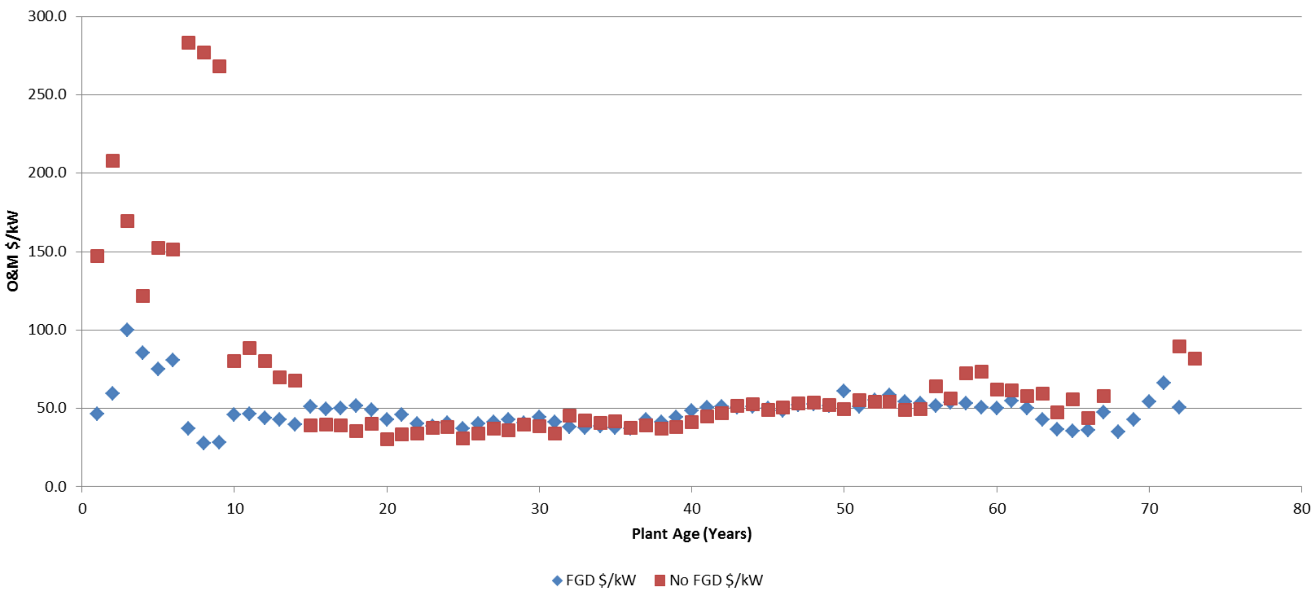
**Figure A-17 — Coal Steam Dataset – CAPEX for FGD/No FGD**




## OPERATIONS & MAINTENANCE EXPENDITURES – FGD VS. NO FGD

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and FGD/no-FGD coefficients are much less than 0.05 (i.e., statistically significant). However, outliers before year 15 may tend to distort the regression analysis. A visual inspection of the difference between the FGD and no-FGD data points in Figure A-18 shows a similarity in O&M spending amounts across all ages after year 15. The differences in annual coal plant spending due to having FGD is more significant in the CAPEX accounts, as shown in the previous subsection, rather than the O&M accounts.

**Figure A-18 — Coal Steam Dataset – O&M for FGD vs. No FGD**



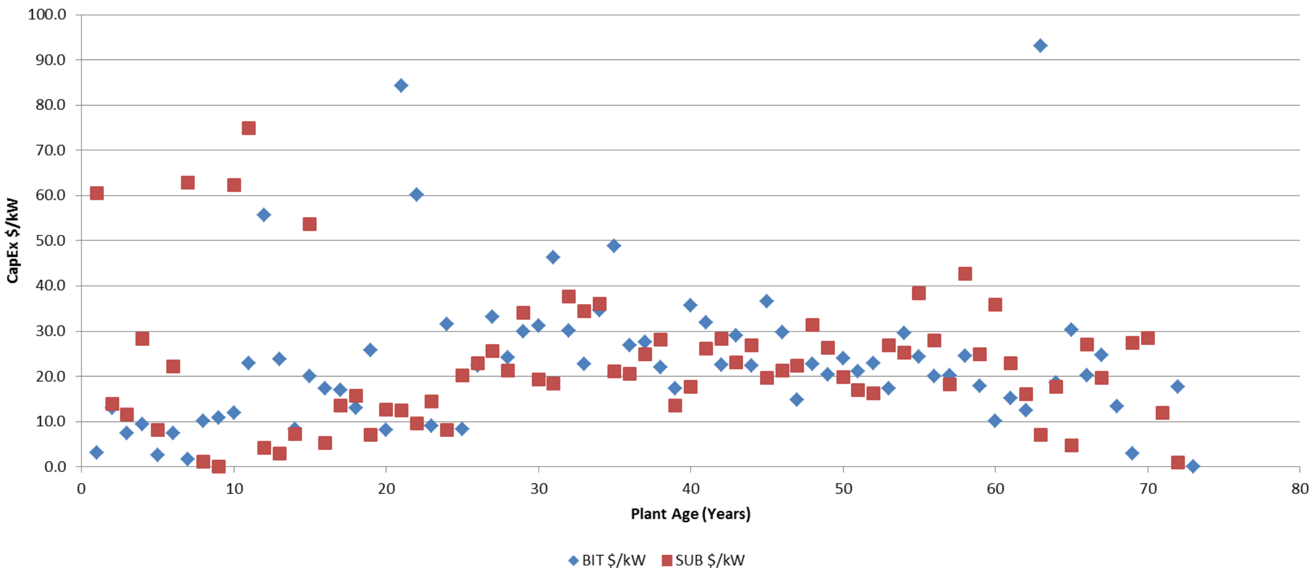

## CAPITAL EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in bituminous versus subbituminous coal types are summarized in the table below. The p-value for the age (“slope”) coefficient is much greater than 0.05 (not statistically significant), while the p-value for the bituminous/subbituminous coefficient is much less than 0.05 (statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-19 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

**Table A-17 — Regression Statistics – Coal CAPEX for Bituminous/Subbituminous**

| | Coefficients | Standard Error | t Stat | P-Value |
|---|---|---|---|---|
| Intercept | 15.39252046 | 2.257695952 | 6.817800442 | 1.08205E-11 |
| Age | -0.00350504 | 0.054578287 | -0.064220408 | 0.948798346 |
| Bit./Sub. (1/0) | 10.93481186 | 1.525466511 | 7.168175624 | 9.20398E-13 |

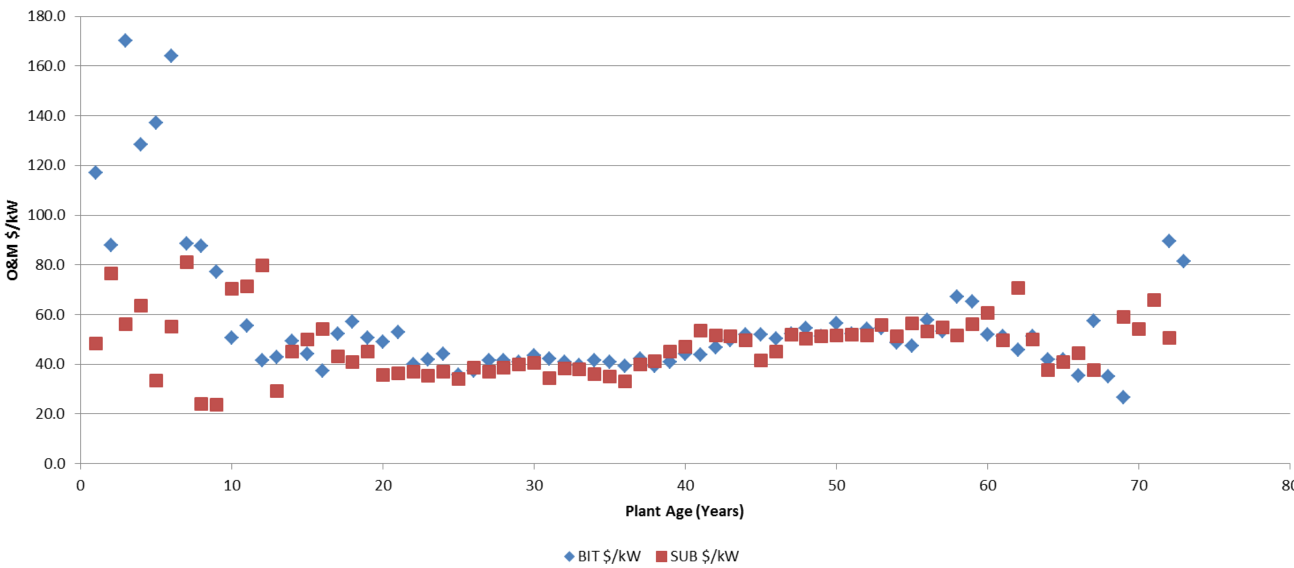
**Figure A-19 — Coal Steam Dataset – CAPEX for Bituminous/Subbituminous**




## OPERATIONS & MAINTENANCE EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and bituminous/subbituminous coefficients are much less than 0.05 (statistically significant). However, as with CAPEX spending, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-20 shows a similarity in O&M spending amounts across all ages. Therefore, average O&M spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

**Figure A-20 — Coal Steam Dataset – O&M for Bituminous vs. Subbituminous**




## EFFECT OF PLANT CAPACITY FACTOR

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time. Figure A-21 and Figure A-22 indicate real annual increases in CAPEX and O&M spending for the coal steam plants in constant 2017 $/MWh versus plant age, with linear regression results as follows:

- Annual CAPEX in 2017 $/MWh = 3.27 + (0.0426 × age)
- Annual O&M in 2017 $/MWh = 5.44 + (0.133 × age)

**Figure A-21 — CAPEX vs. Age for All MW Coal Plants (2017 $/MWh)**

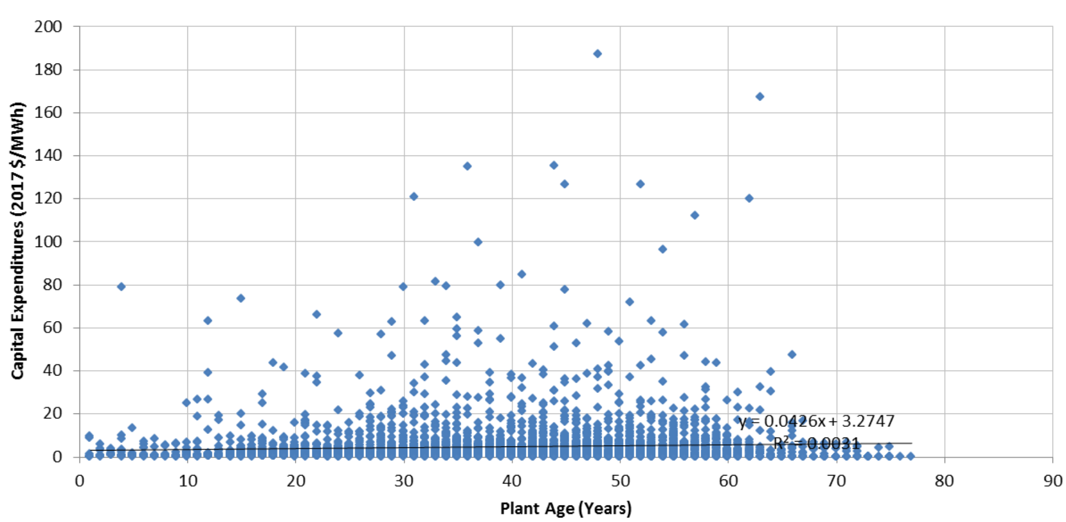
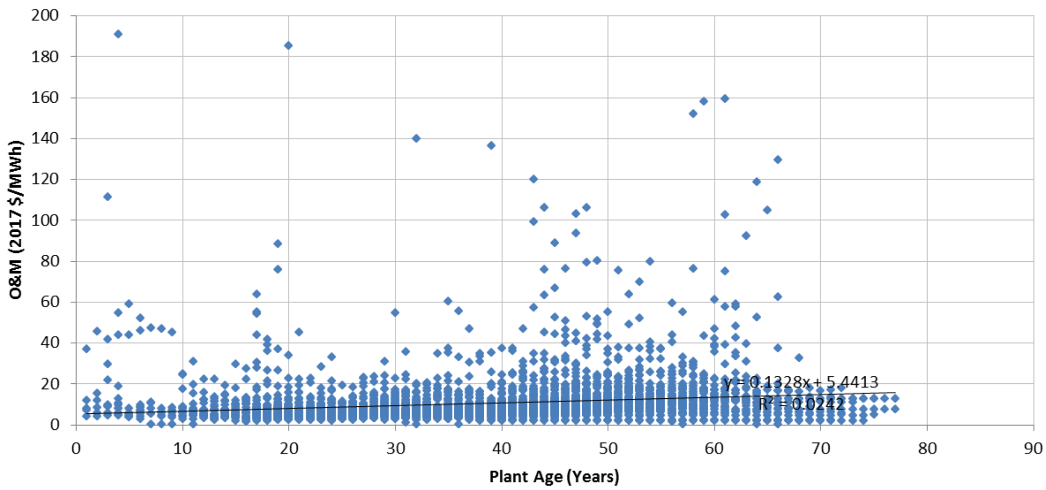
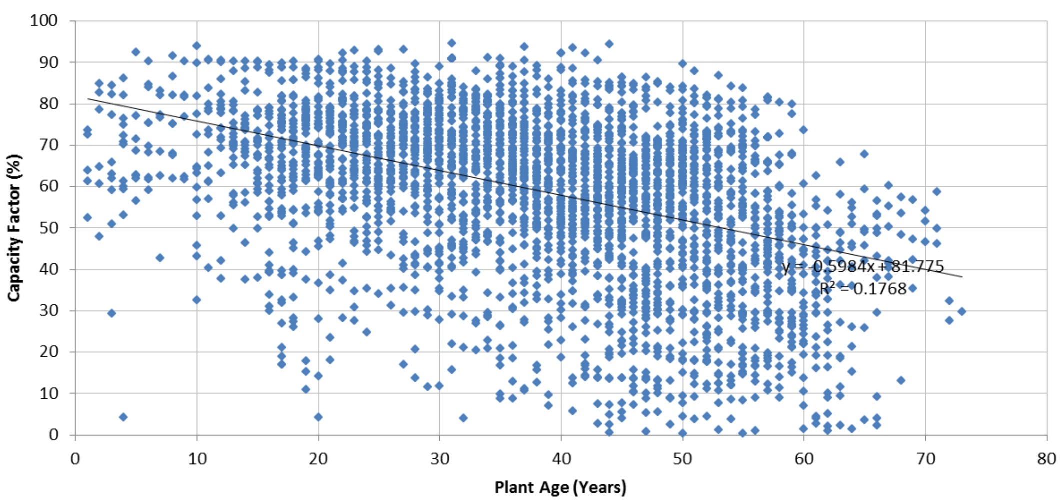


**Figure A-22 — O&M vs. Age for All Coal Plants (2017 $/MWh)**

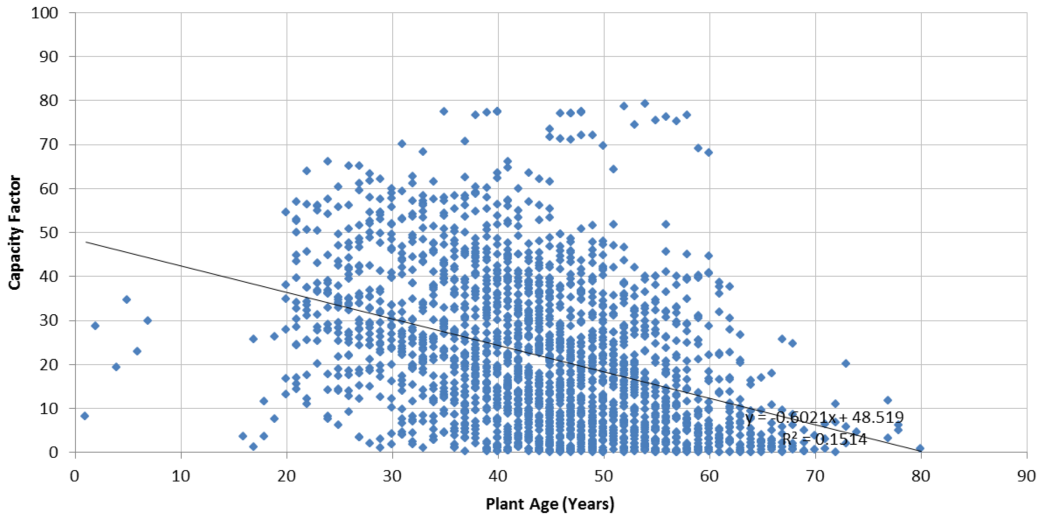



In both of the above regression results, the age coefficient was found to be statistically significant. This was determined to be a result of the average decline in capacity factors for the coal steam plants, as shown in Figure A-23. A similar decline also occurred with the gas/oil steam plants, as shown in Figure A-24.

**Figure A-23 — Capacity Factor vs. Age for All Coal Plants**



## Figure A-24 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



# Appendix B. Regression Analysis – Gas/Oil Steam

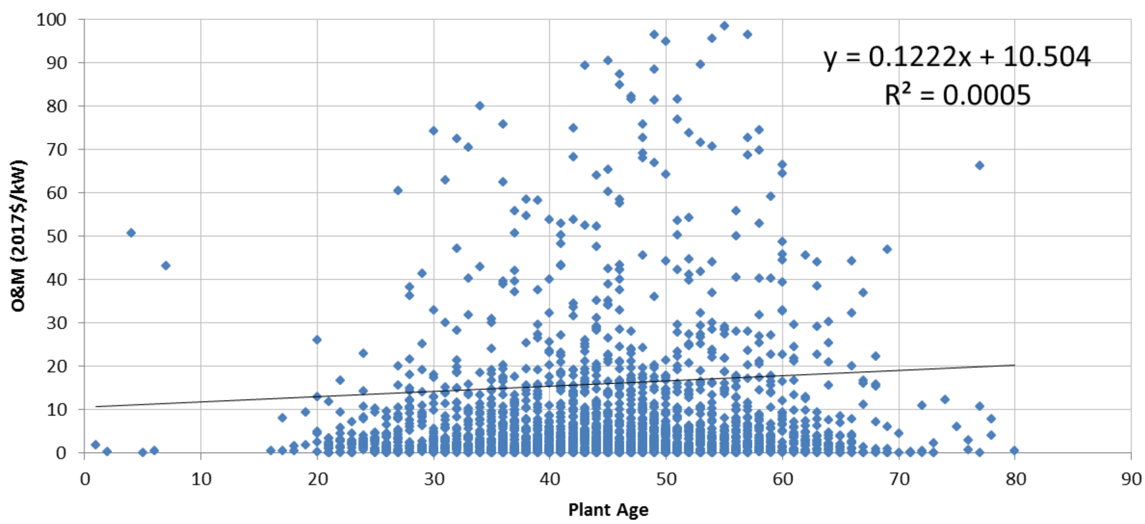
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.29, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table B-1 — Regression Statistics – Gas/Oil Steam CAPEX for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2,226 | | |
| **Simple Average ($/kW)** | 15.955 | | |
| **Intercept** | 10.504 | 1.9741 | 4.85E-02 |
| **Slope** | 0.122 | 1.0551 | 2.91E-01 |
| **$R^2$** | 0.00050 | | |

**Figure B-1 — Gas/Oil Steam Dataset – CAPEX for All Plant MW Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

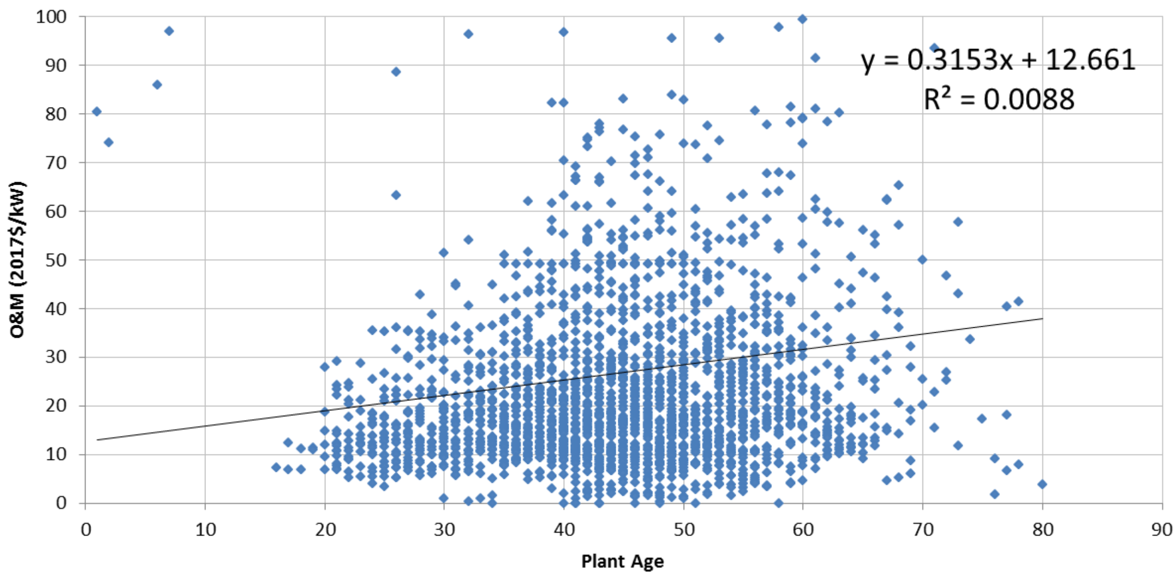
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

## Table B-2 — Regression Statistics – Gas/Oil Steam O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2,224 | | |
| **Simple Average ($/kW)** | 26.723 | | |
| **Intercept** | 12.661 | 3.8863 | 1.05E-04 |
| **Slope** | 0.315 | 4.4455 | 9.20E-06 |
| **$R^2$** | 0.00882 | | |

## Figure B-2 — Gas/Oil Steam Dataset – O&M for All Plant MW Sizes




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 39.39 | 23.48 | 28.18 | **26.72** | 19 | 733 | 1,472 | **2,224** |
| Net Total Capex - 2017 $/kW | 8.91 | 14.18 | 16.93 | **15.96** | 19 | 733 | 1,474 | **2,226** |
| Net Total O&M and Capex - 2017 $/kW | 48.30 | 37.53 | 45.10 | **42.63** | 19 | 731 | 1,470 | **2,220** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

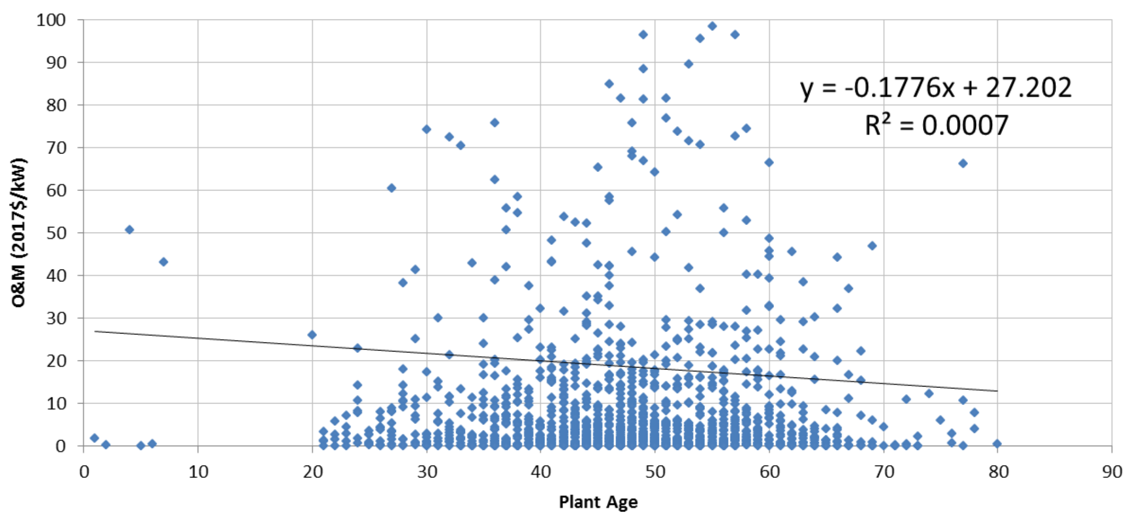
## CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.32, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table B-3 — Regression Statistics – Gas/Oil Steam CAPEX < 500 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1382 | | |
| **Simple Average ($/kW)** | 18.392 | | |
| **Intercept** | 27.202 | 3.1265 | 1.81E-03 |
| **Slope** | -0.178 | -0.9867 | 3.24E-01 |
| **$R^2$** | 0.00071 | | |

**Figure B-3 — Gas/Oil Steam Dataset – CAPEX for Less than 500-MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

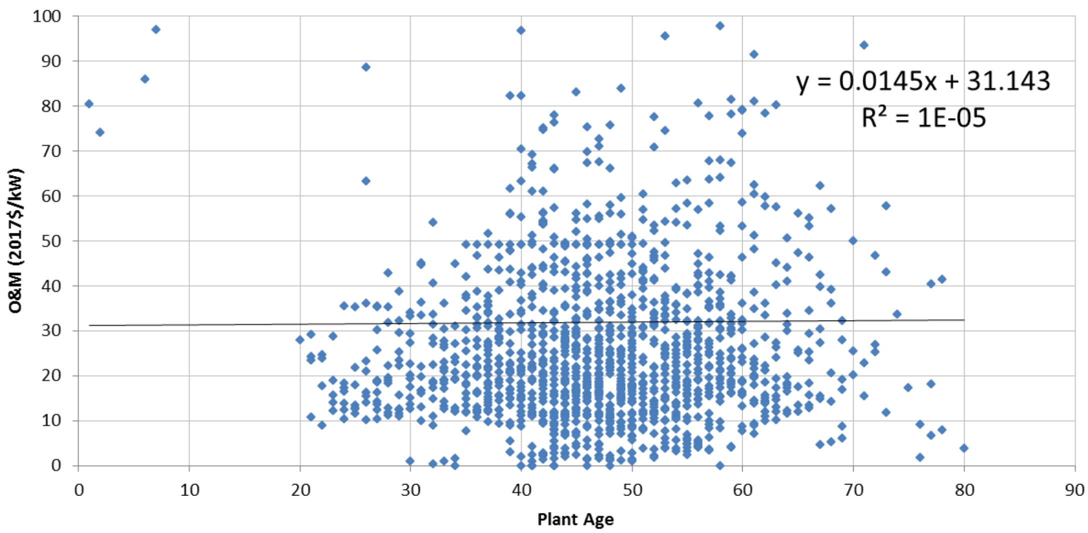
## OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of O&M spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.90, which is greater than 0.05, age is not a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

**Table B-4 — Regression Statistics – Gas/Oil Steam O&M < 500 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,381 | | |
| **Simple Average ($/kW)** | 31.827 | | |
| **Intercept** | 31.143 | 5.7925 | 8.58E-09 |
| **Slope** | 0.015 | 0.1305 | 8.96E-01 |
| **$R^2$** | 0.00001 | | |

**Figure B-4 — Gas/Oil Steam Dataset – O&M for Less than 500-MW Plant Size**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **< 500 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 88.54 | 33.36 | 30.98 | **31.83** | 7 | 324 | 1,050 | **1,381** |
| Net Total Capex - 2017 $/kW | 17.44 | 22.13 | 17.82 | **18.83** | 7 | 324 | 1,051 | **1,382** |
| Net Total O&M and Capex - 2017 $/kW | 105.98 | 55.32 | 48.78 | **50.60** | 7 | 322 | 1,048 | **1,377** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

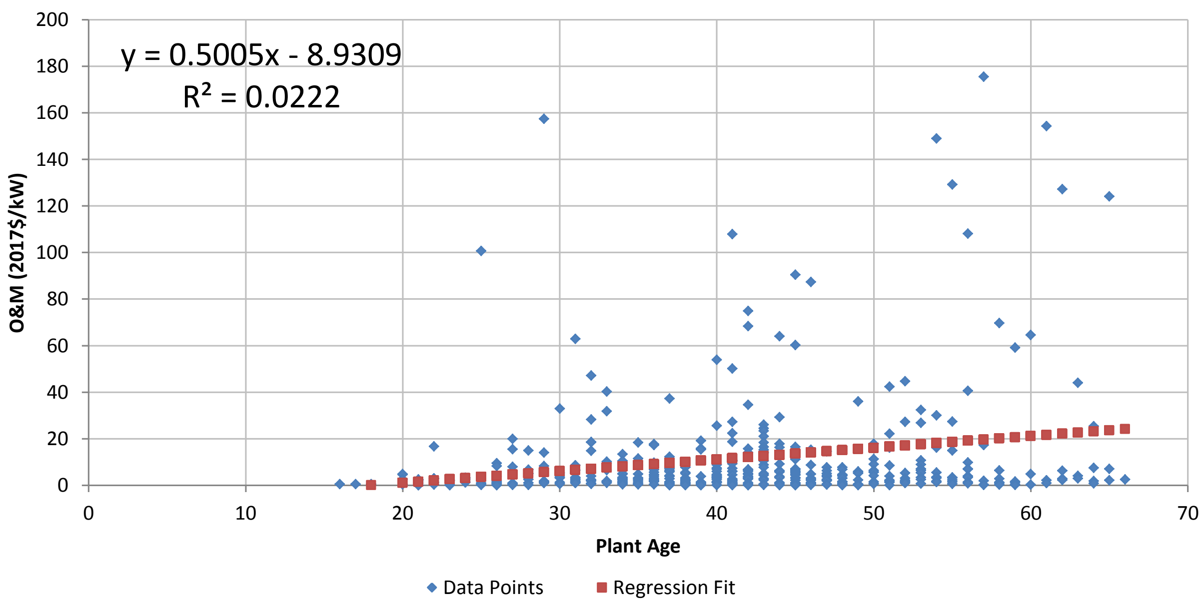
## CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

### Table B-5 — Regression Statistics – Gas/Oil Steam CAPEX 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 489 | | |
| **Simple Average ($/kW)** | 11.570 | | |
| **Intercept** | -8.988 | -1.4118 | 1.59E-01 |
| **Slope** | 0.501 | 3.3322 | 9.27E-04 |
| **$R^2$** | 0.02229 | | |

### Figure B-5 — Gas/Oil Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



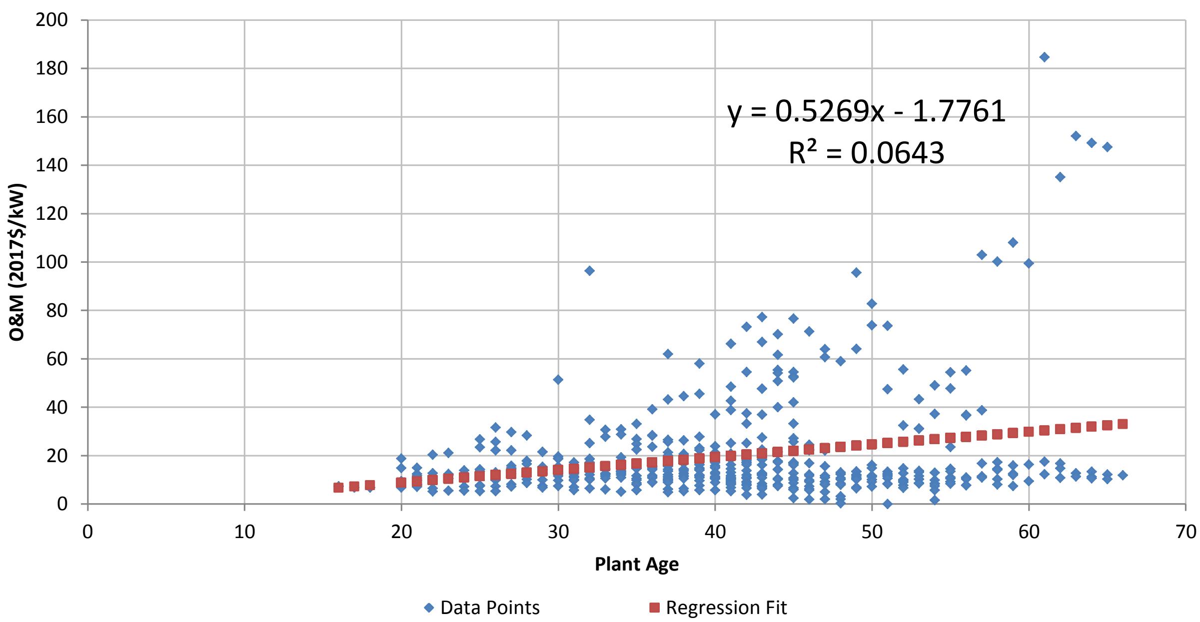
## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending. However, the regression analysis shows the intercept value (i.e., the O&M cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited data causes the regression analysis to be distorted.

### Table B-6 — Regression Statistics – Gas/Oil Steam O&M 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 488 | | |
| **Simple Average ($/kW)** | 19.823 | | |
| **Intercept** | -1.776 | -0.4606 | 6.45E-01 |
| **Slope** | 0.527 | 5.7810 | 1.33E-08 |
| **$R^2$** | 0.06434 | | |

### Figure B-6 — Gas/Oil Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **500 MW - 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 10.10 | 15.82 | 23.61 | **19.82** | 7 | 225 | 256 | **488** |
| Net Total Capex - 2017 $/kW | 1.94 | 6.32 | 16.43 | **11.57** | 7 | 225 | 257 | **489** |
| Net Total O&M and Capex - 2017 $/kW | 12.04 | 22.14 | 40.07 | **31.40** | 7 | 225 | 256 | **488** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

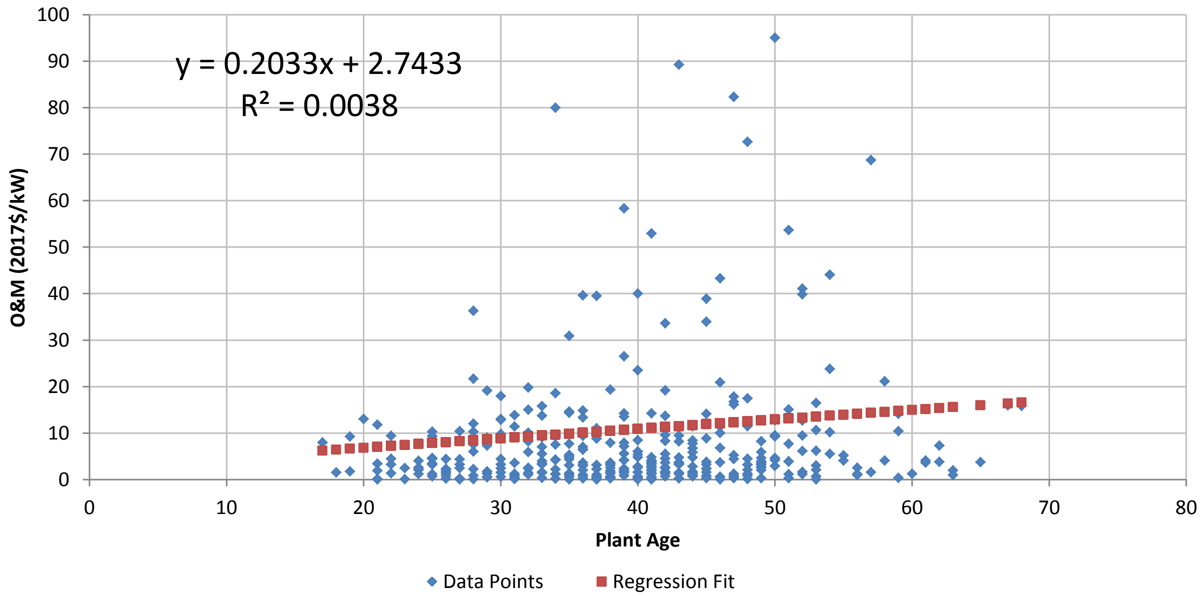
## CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.24, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table B-7 — Regression Statistics – Gas/Oil Steam CAPEX > 1,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 355 | | |
| **Simple Average ($/kW)** | 10.815 | | |
| **Intercept** | 2.743 | 0.3846 | 7.01E-01 |
| **Slope** | 0.203 | 1.1660 | 2.44E-01 |
| **$R^2$** | 0.00384 | | |

**Figure B-7 — Gas/Oil Steam Dataset – CAPEX for Greater than 1,000-MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

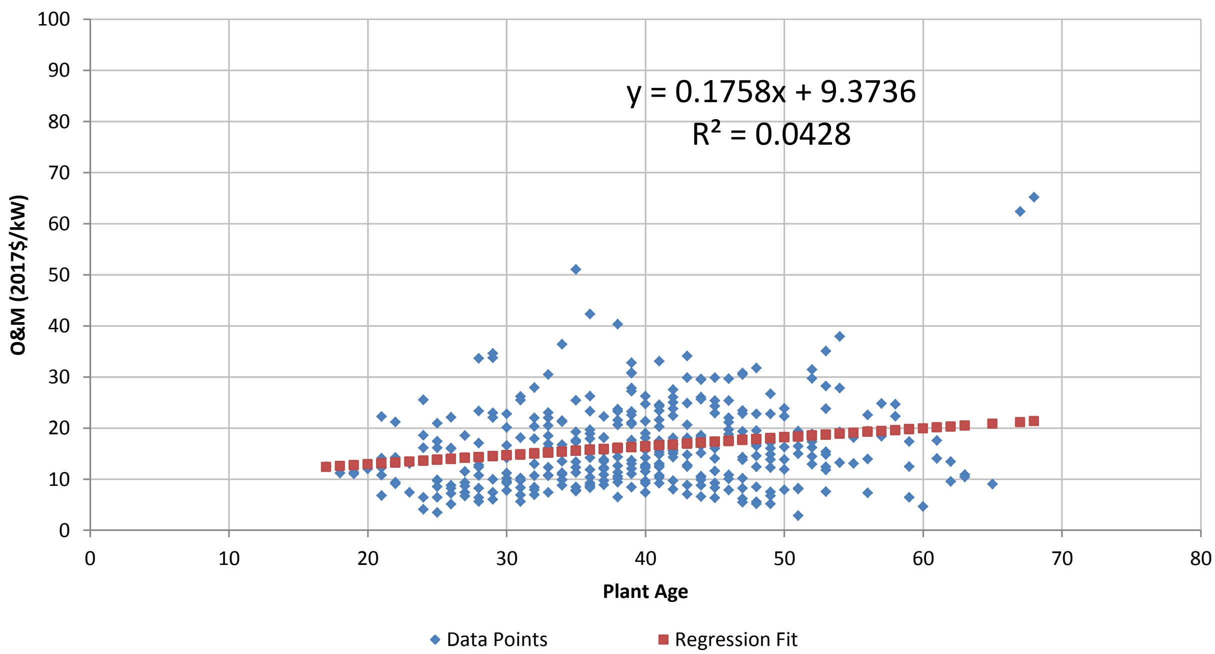
## OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

**Table B-8 — Regression Statistics – Gas/Oil Steam O&M > 1,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 355 | | |
| **Simple Average ($/kW)** | 16.353 | | |
| **Intercept** | 9.374 | 5.1812 | 3.71E-07 |
| **Slope** | 0.176 | 3.9752 | 8.53E-05 |
| **$R^2$** | 0.04285 | | |

**Figure B-8 — Gas/Oil Steam Dataset – O&M for Greater than 1,000-MW Plant Size**




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **> 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 11.59 | 15.44 | 17.50 | **16.35** | 5 | 184 | 166 | **355** |
| Net Total Capex - 2017 $/kW | 6.70 | 9.78 | 12.09 | **10.82** | 5 | 184 | 166 | **355** |
| Net Total O&M and Capex - 2017 $/kW | 18.29 | 25.22 | 29.60 | **27.17** | 5 | 184 | 166 | **355** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

# Appendix C. Regression Analysis – Gas/Oil Combined Cycle

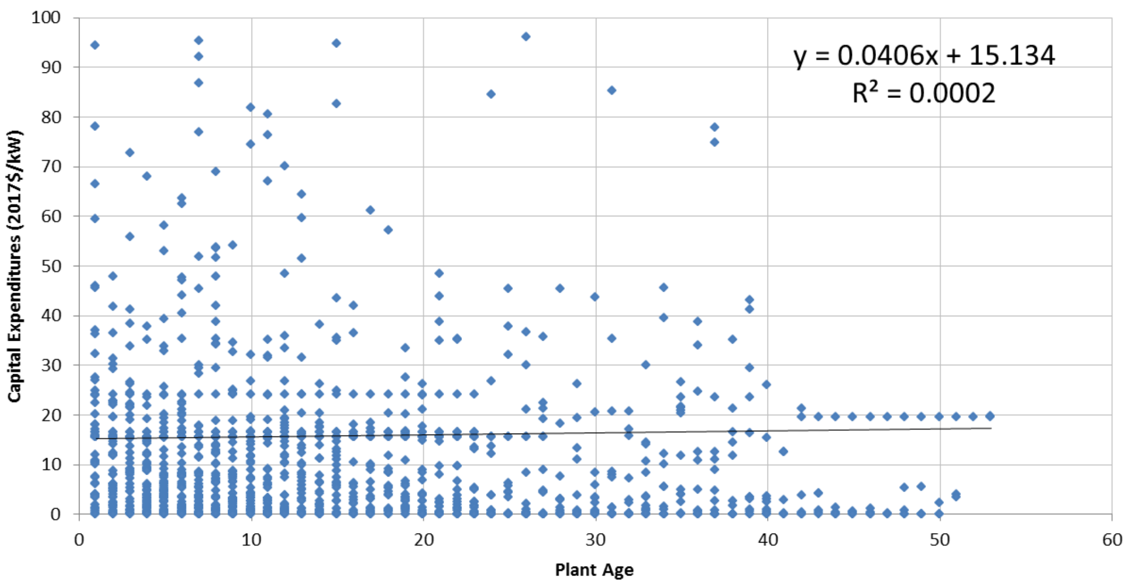
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.63, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table C-1 — Regression Statistics – CC CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,368 | | |
| **Simple Average ($/kW)** | 15.765 | | |
| **Intercept** | 15.134 | 9.2176 | 1.11E-19 |
| **Slope** | 0.041 | 0.4853 | 6.28E-01 |
| **$R^2$** | 0.00017 | | |

### Figure C-1 — Gas/Oil CC Dataset – CAPEX for All Plant MW Sizes




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

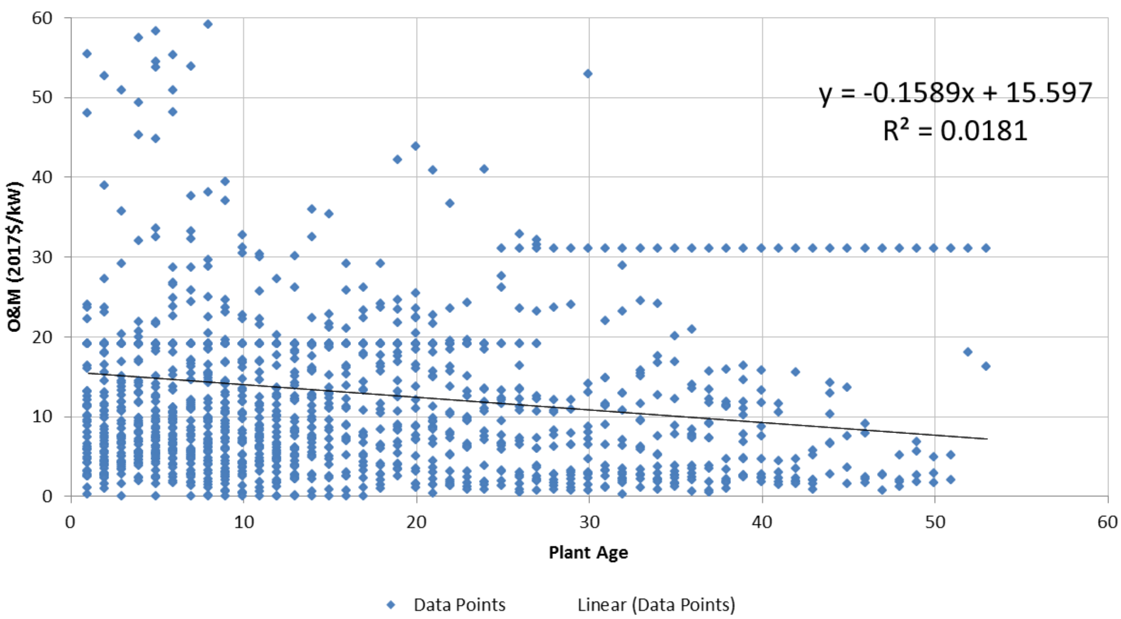
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is much lower than 0.05, the dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

## Table C-2 — Regression Statistics – CC O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,388 | | |
| **Simple Average ($/kW)** | 13.080 | | |
| **Intercept** | 15.597 | 24.8961 | 2.19E-113 |
| **Slope** | -0.159 | -5.0573 | 4.82E-07 |
| **$R^2$** | 0.01812 | | |

## Figure C-2 — Gas/Oil CC Dataset – O&M for All Plant MW Sizes




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 14.16 | 10.56 | 10.26 | **13.08** | 978 | 344 | 66 | **1,388** |
| Net Total Capex - 2017 $/kW | 15.45 | 16.37 | 17.56 | **15.76** | 979 | 326 | 63 | **1,368** |
| Net Total O&M and Capex - 2017 $/kW | 29.64 | 27.24 | 28.19 | **29.00** | 976 | 326 | 63 | **1,365** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

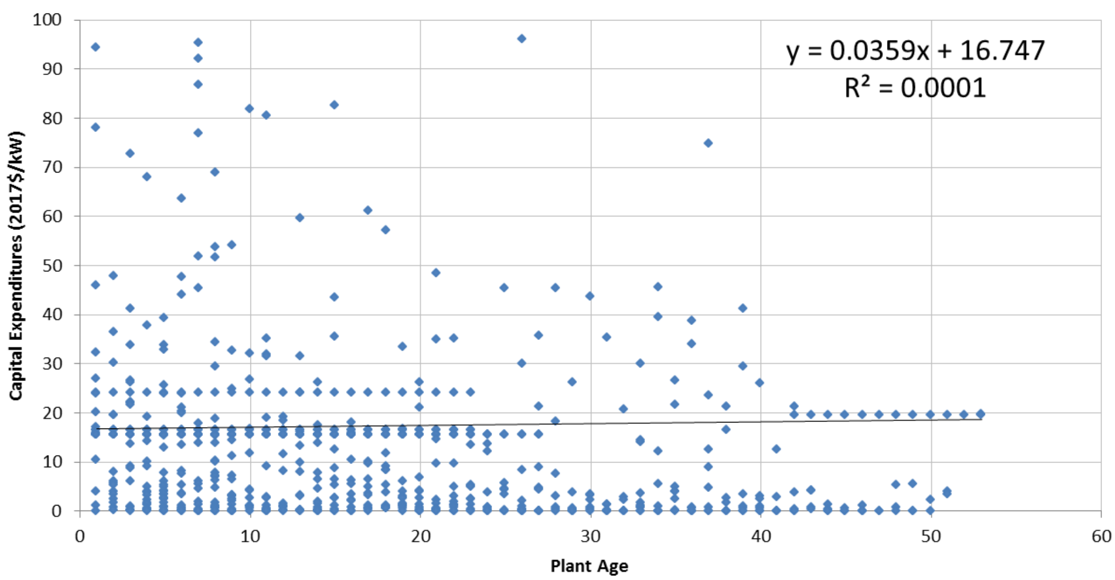
## CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants under 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.76, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table C-3 — Regression Statistics – CC CAPEX < 500 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 765 | | |
| **Simple Average ($/kW)** | 17.378 | | |
| **Intercept** | 16.747 | 6.4870 | 1.57E-10 |
| **Slope** | 0.036 | 0.3007 | 7.64E-01 |
| **$R^2$** | 0.00012 | | |

**Figure C-3 — Gas/Oil CC Dataset – CAPEX for Less than 500-MW Plant Size**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

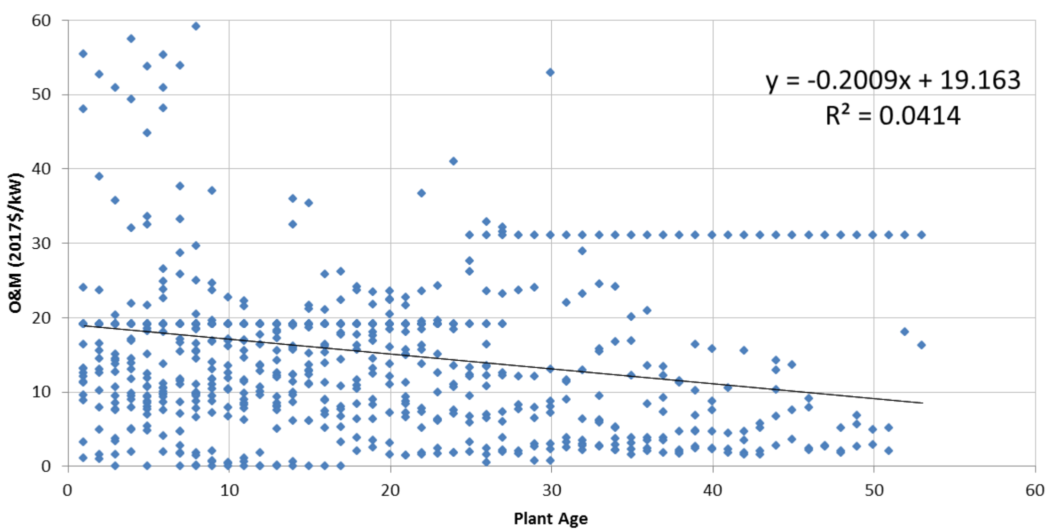
## OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of O&M spending for gas/oil CC plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

### Table C-4 — Regression Statistics – CC O&M < 500 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 766 | | |
| **Simple Average ($/kW)** | 15.619 | | |
| **Intercept** | 19.163 | 25.2973 | 4.82E-103 |
| **Slope** | -0.201 | -5.7467 | 1.31E-08 |
| **$R^2$** | 0.04143 | | |

### Figure C-4 — Gas/Oil CC Dataset – O&M for Less than 500-MW Plant Size




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average \$/kW (years 1 - 20) = | Average \$/kW (years 21 - 40) = | Average \$/kW (years 41 - 80) = | **Average \$/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **< 500 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 \$/kW | 17.10 | 13.01 | 12.27 | **15.62** | 498 | 216 | 52 | **766** |
| Net Total Capex - 2017 \$/kW | 16.83 | 17.78 | 21.01 | **17.38** | 499 | 214 | 52 | **765** |
| Net Total O&M and Capex - 2017 \$/kW | 34.00 | 30.72 | 33.28 | **33.03** | 497 | 214 | 52 | **763** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

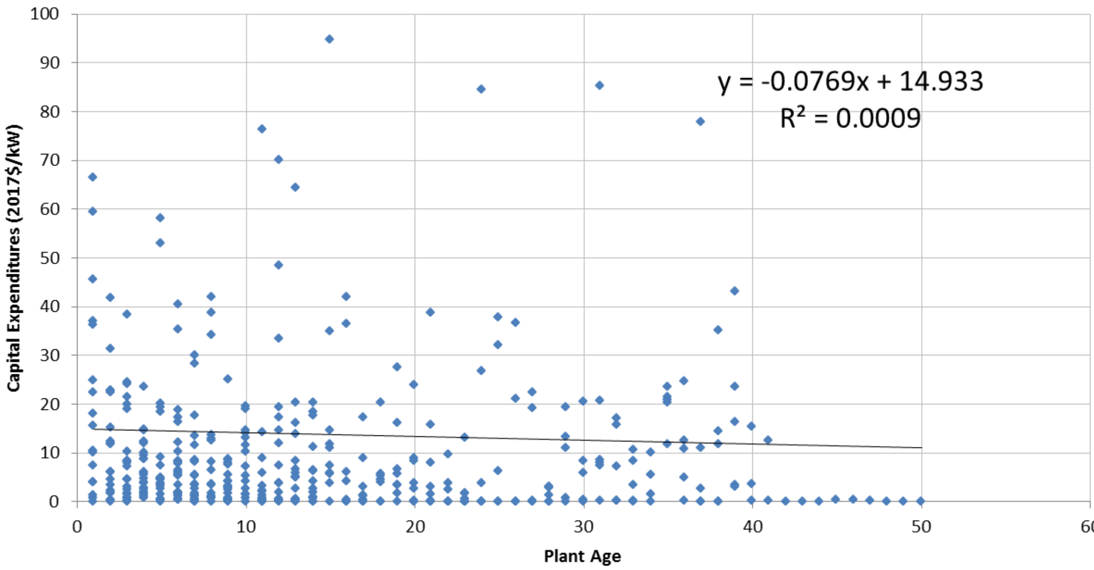
## CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.52, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table C-5 — Regression Statistics – CC CAPEX 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 426 | | |
| **Simple Average (\$/kW)** | 13.780 | | |
| **Intercept** | 14.933 | 6.3972 | 4.19E-10 |
| **Slope** | -0.077 | -0.6252 | 5.32E-01 |
| **$R^2$** | 0.00092 | | |

### Figure C-5 — Gas/Oil CC Dataset – CAPEX for 500-MW to 1,000-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

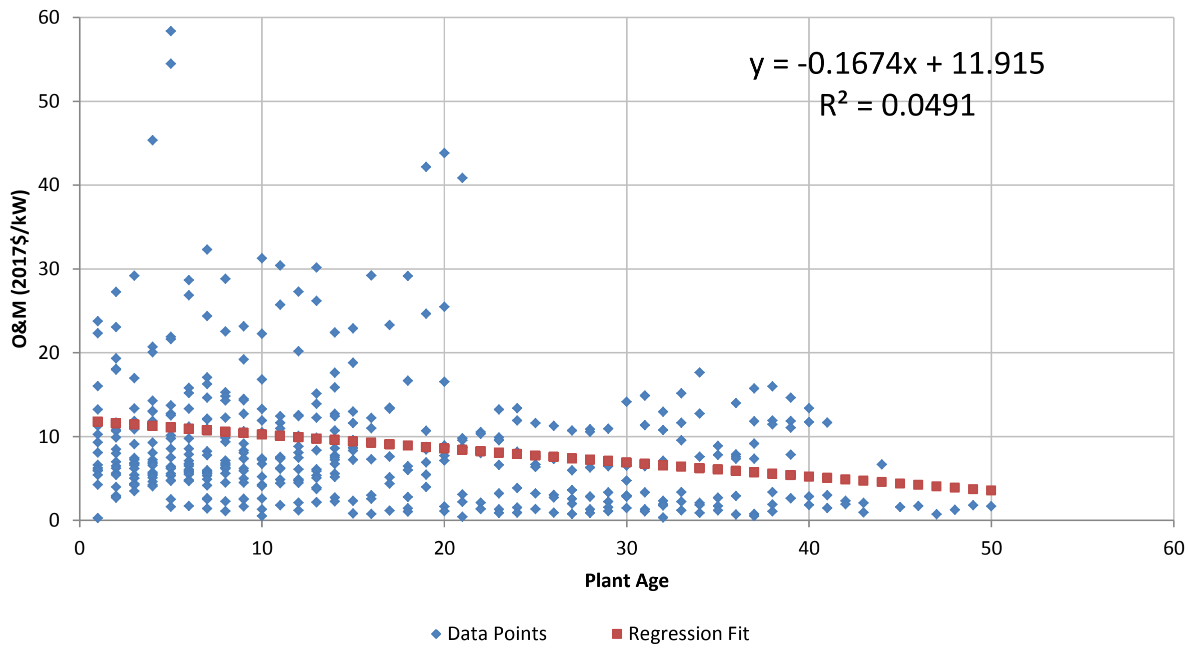
## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

### Table C-6 — Regression Statistics – CC O&M 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 445 | | |
| **Simple Average ($/kW)** | 9.269 | | |
| **Intercept** | 11.915 | 17.1008 | 1.04E-50 |
| **Slope** | -0.167 | -4.7810 | 2.38E-06 |
| **$R^2$** | 0.04907 | | |

**Figure C-6 — Gas/Oil CC Dataset – O&M for 500-MW to 1,000-MW Plant Size**




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **500 MW - 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 10.68 | 6.50 | 2.78 | **9.27** | 307 | 124 | 14 | **445** |
| Net Total Capex - 2017 $/kW | 14.38 | 13.36 | 1.28 | **13.78** | 307 | 108 | 11 | **426** |
| Net Total O&M and Capex - 2017 $/kW | 25.06 | 20.38 | 4.15 | **23.33** | 306 | 108 | 11 | **425** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

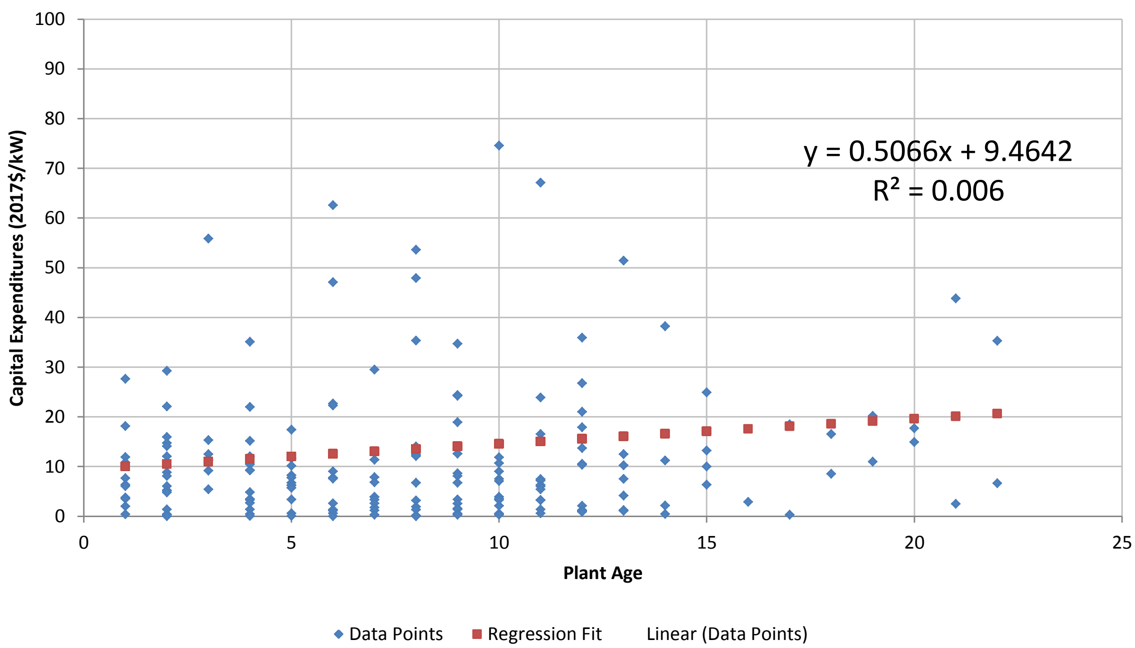
## CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.30, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table C-7 — Regression Statistics – CC CAPEX > 1,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 177 | | |
| **Simple Average ($/kW)** | 13.566 | | |
| **Intercept** | 9.464 | 2.0308 | 4.38E-02 |
| **Slope** | 0.507 | 1.0309 | 3.04E-01 |
| **$R^2$** | 0.00604 | | |

**Figure C-7 — Gas/Oil CC Dataset – CAPEX for Greater than 1,000-MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

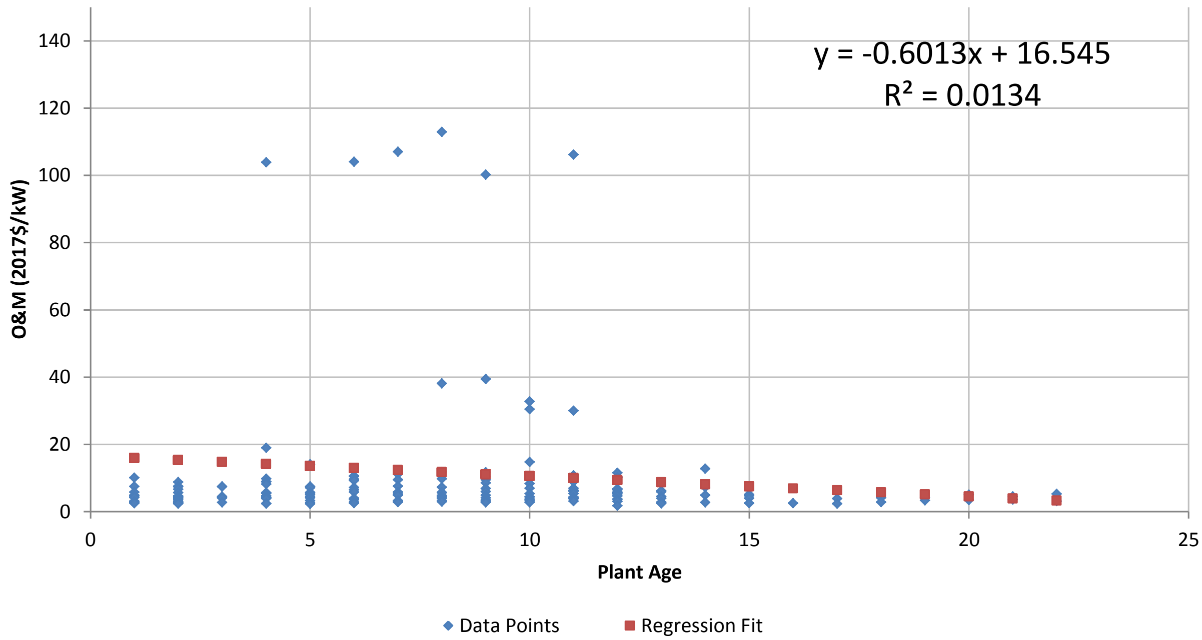
## OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.13, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

**Table C-8 — Regression Statistics – CC O&M > 1,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 177 | | |
| **Simple Average ($/kW)** | 11.676 | | |
| **Intercept** | 16.545 | 4.4651 | 1.43E-05 |
| **Slope** | -0.601 | -1.5389 | 1.26E-01 |
| **$R^2$** | 0.01335 | | |

**Figure C-8 — Gas/Oil CC Dataset – O&M for Greater than 1,000 MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **> 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 11.85 | 4.14 | - | **11.68** | 173 | 4 | 0 | **177** |
| Net Total Capex - 2017 $/kW | 13.37 | 22.06 | - | **13.57** | 173 | 4 | 0 | **177** |
| Net Total O&M and Capex - 2017 $/kW | 25.22 | 26.20 | - | **25.24** | 173 | 4 | 0 | **177** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

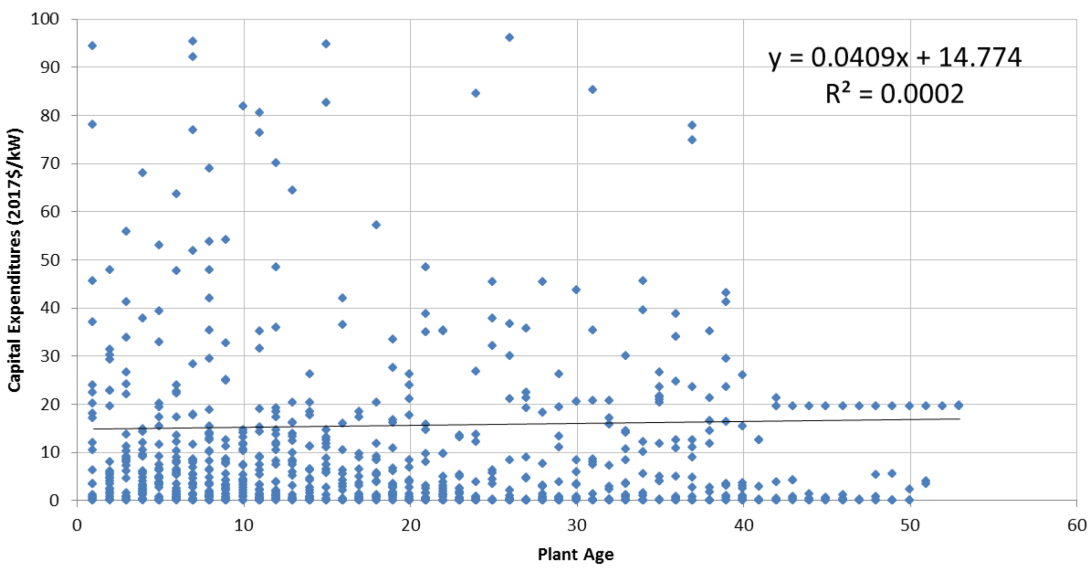
## CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.71, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table C-9 — Regression Statistics – CC CAPEX for Capacity Factor < 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 844 | | |
| **Simple Average ($/kW)** | 15.554 | | |
| **Intercept** | 14.774 | 5.7075 | 1.59E-08 |
| **Slope** | 0.041 | 0.3659 | 7.15E-01 |
| **$R^2$** | 0.00016 | | |

**Figure C-9 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor < 50%**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

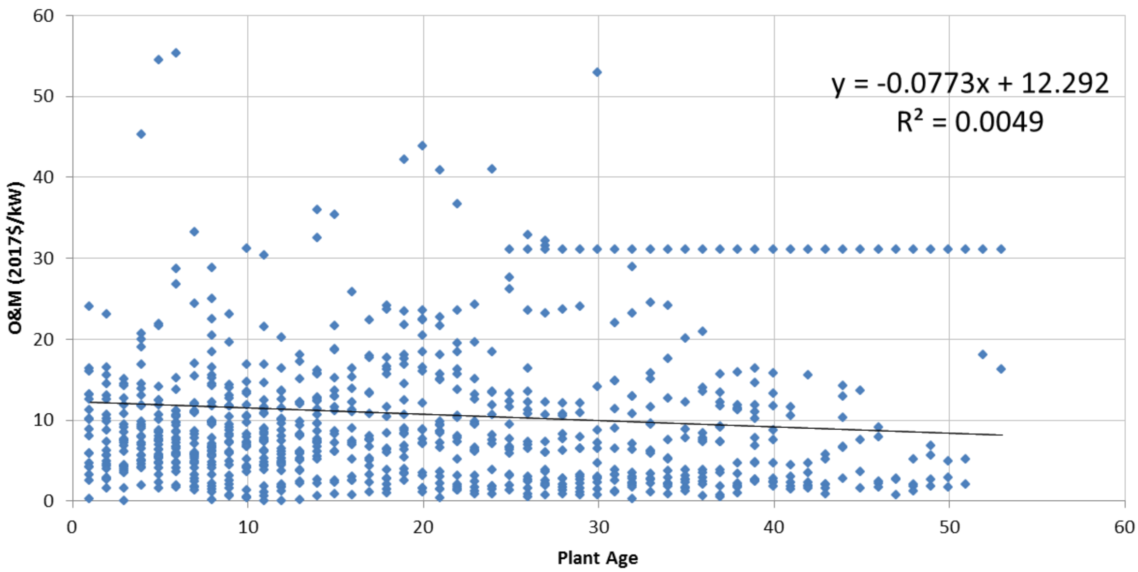
## OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

**Table C-10 — Regression Statistics – CC O&M for Capacity Factor < 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 864 | | |
| **Simple Average ($/kW)** | 10.791 | | |
| **Intercept** | 12.292 | 13.9850 | 3.33E-40 |
| **Slope** | -0.077 | -2.0625 | 3.95E-02 |
| **$R^2$** | 0.00491 | | |

**Figure C-10 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor < 50%**




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, Capacity Factors 0 - 50%** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 11.54 | 9.65 | 10.26 | **10.79** | 500 | 298 | 66 | **864** |
| Net Total Capex - 2017 $/kW | 15.35 | 15.46 | 17.56 | **15.55** | 501 | 280 | 63 | **844** |
| Net Total O&M and Capex - 2017 $/kW | 26.95 | 25.41 | 28.19 | **26.53** | 499 | 280 | 63 | **842** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

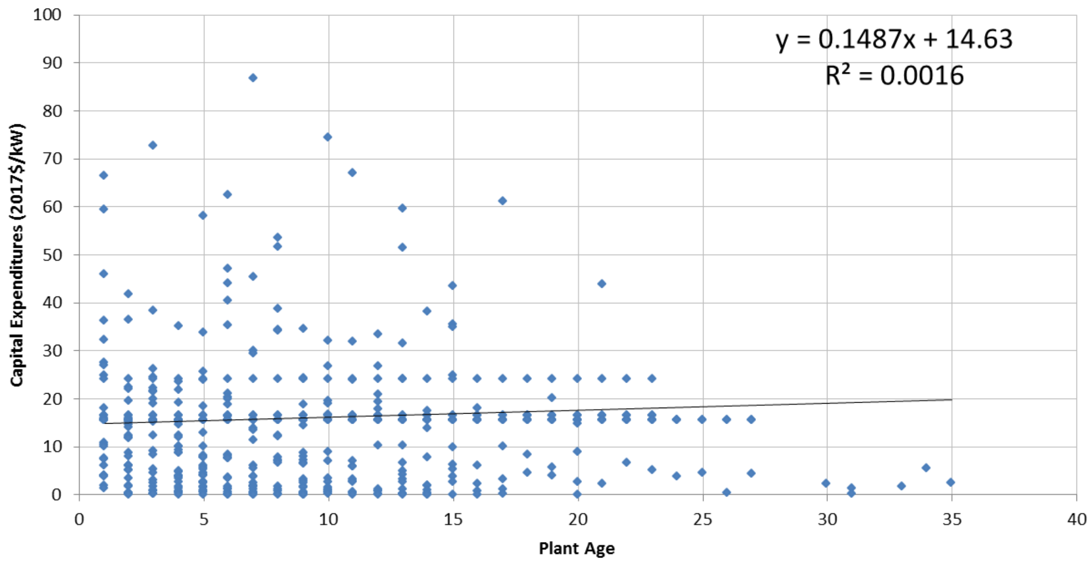
## CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.37, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table C-11 — Regression Statistics – CC CAPEX for Capacity Factor > 50%

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 524 | | |
| **Simple Average ($/kW)** | 16.104 | | |
| **Intercept** | 14.630 | 7.3893 | 5.90E-13 |
| **Slope** | 0.149 | 0.9054 | 3.66E-01 |
| **$R^2$** | 0.00157 | | |

**Figure C-11 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor > 50%**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

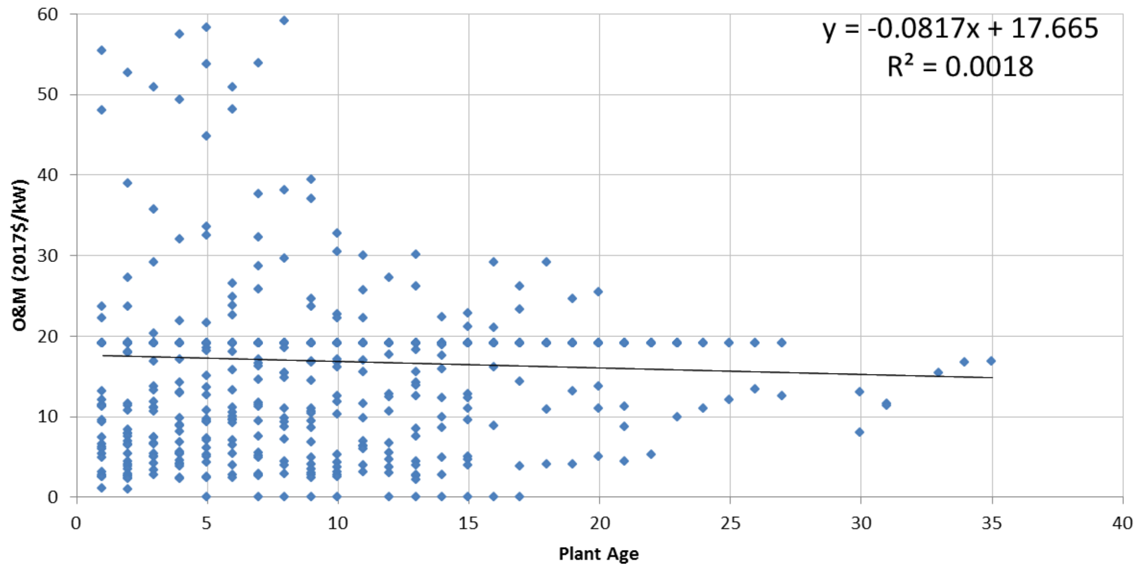
## OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below. Since the p-value for the age coefficient ("slope") is 0.33, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table C-12 — Regression Statistics – CC O&M for Capacity Factor > 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 524 | | |
| **Simple Average ($/kW)** | 16.855 | | |
| **Intercept** | 17.665 | 17.5298 | 1.93E-54 |
| **Slope** | -0.082 | -0.9777 | 3.29E-01 |
| **$R^2$** | 0.00183 | | |

**Figure C-12 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor > 50%**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

| | Average \$/kW (years 1 - 20) = | Average \$/kW (years 21 - 40) = | Average \$/kW (years 41 - 80) = | **Average \$/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, Capacity Factors 50% - 100%** | | | | | | | | |
| Net Total O&M- 2017 \$/kW | 16.90 | 16.44 | - | **16.85** | 478 | 46 | 0 | **524** |
| Net Total Capex - 2017 \$/kW | 15.55 | 21.89 | - | **16.10** | 478 | 46 | 0 | **524** |
| Net Total O&M and Capex - 2017 \$/kW | 32.46 | 38.32 | - | **32.98** | 477 | 46 | 0 | **523** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

# Appendix D. Regression Analysis – Gas/Oil Combustion Turbine

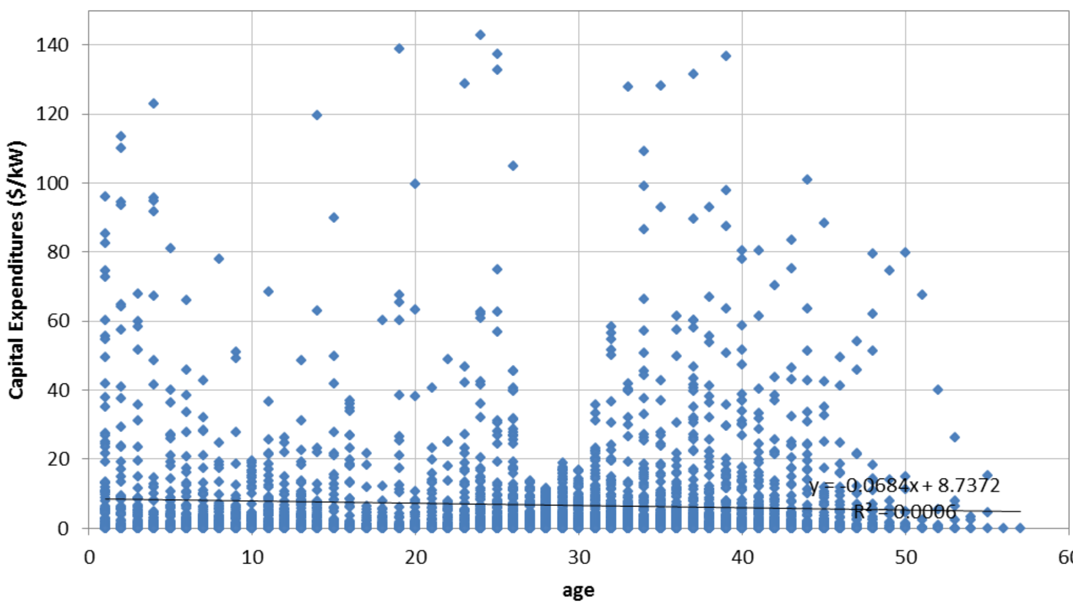
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.09, which is greater than 0.05, dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table D-1 — Regression Statistics – CT CAPEX for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 5065 | | |
| **Simple Average ($/kW)** | 6.897 | | |
| **Intercept** | 8.737 | 7.3087 | 3.12E-13 |
| **Slope** | -0.068 | -1.6948 | 9.02E-02 |
| **$R^2$** | 0.00057 | | |

**Figure D-1 — Gas/Oil CT Dataset – CAPEX for All Plant MW Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

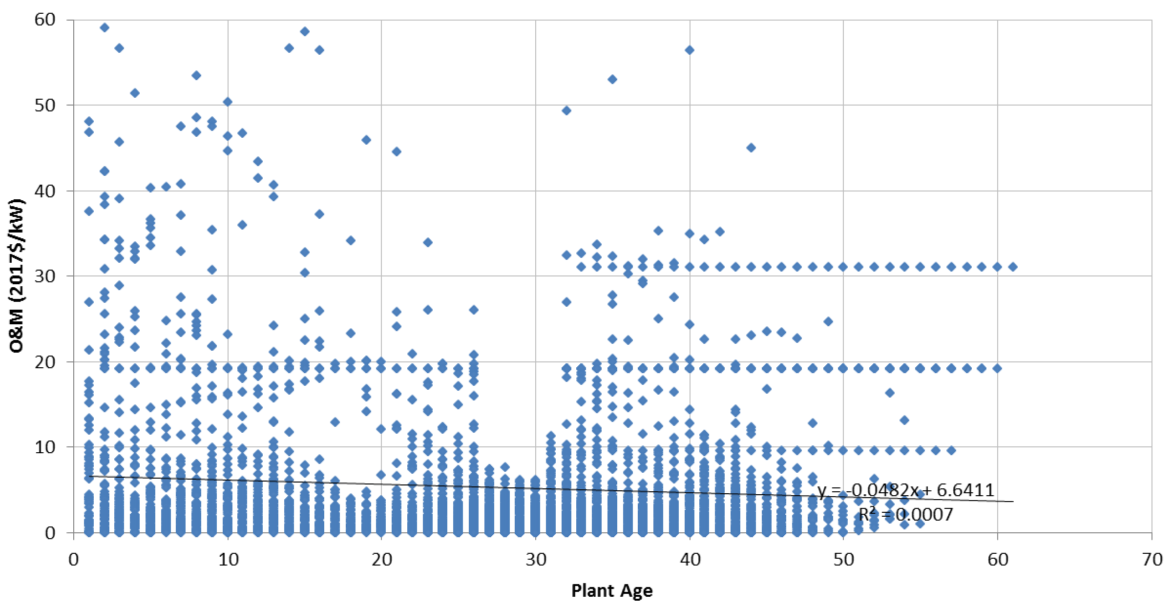
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of O&M spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.062, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

## Table D-2 — Regression Statistics – CT O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 5283 | | |
| **Simple Average ($/kW)** | 5.331 | | |
| **Intercept** | 6.641 | 8.5764 | 1.27E-17 |
| **Slope** | -0.048 | -1.8683 | 6.18E-02 |
| **$R^2$** | 0.00066 | | |

## Figure D-2 — Gas/Oil CT Dataset – O&M for All Plant MW Sizes




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 7.86 | 3.99 | 6.11 | **5.33** | 1,418 | 3,118 | 747 | **5,283** |
| Net Total Capex - 2017 $/kW | 9.17 | 5.78 | 7.40 | **6.90** | 1,360 | 3,054 | 651 | **5,065** |
| Net Total O&M and Capex - 2017 $/kW | 16.43 | 9.43 | 10.92 | **11.49** | 1,341 | 3,040 | 640 | **5,021** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

## CAPITAL EXPENDITURES – LESS THAN 100 MW

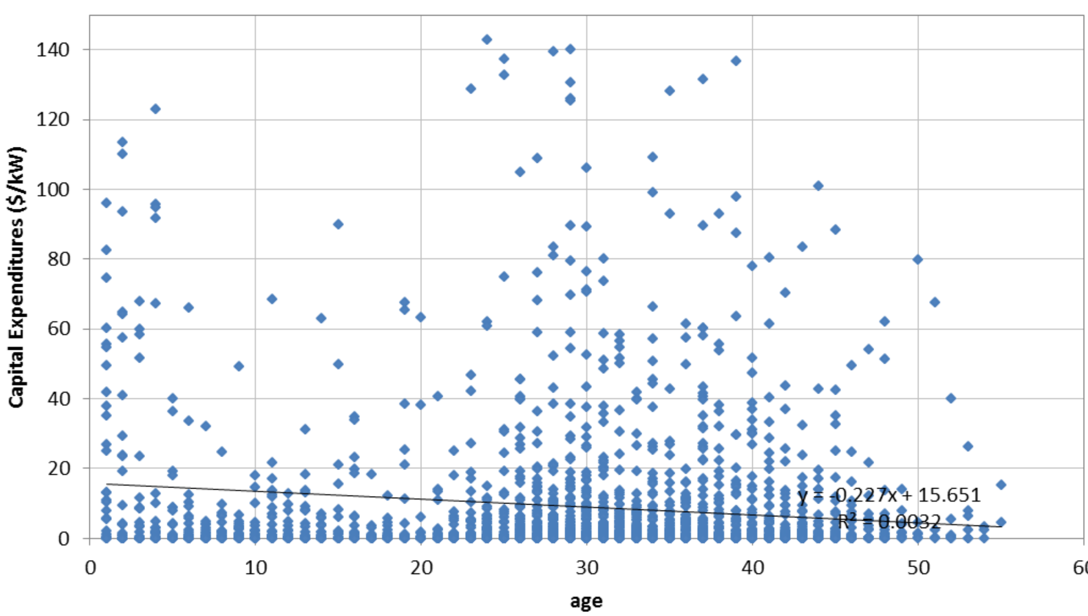
The results of the regression analysis of CAPEX spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.002, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

| **Annual CAPEX spending in 2017 \$/kW-year = 15.651 + (-0.227 × age)** |
|---|

**Table D-3 — Regression Statistics – CT CAPEX < 100 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2,911 | | |
| **Simple Average (\$/kW)** | 9.003 | | |
| **Intercept** | 15.651 | 6.6753 | 2.94E-11 |
| **Slope** | -0.227 | -3.0345 | 2.43E-03 |
| **$R^2$** | 0.00316 | | |

**Figure D-3 — Gas/Oil CT Dataset – CAPEX for Less than 100-MW Plant Size**



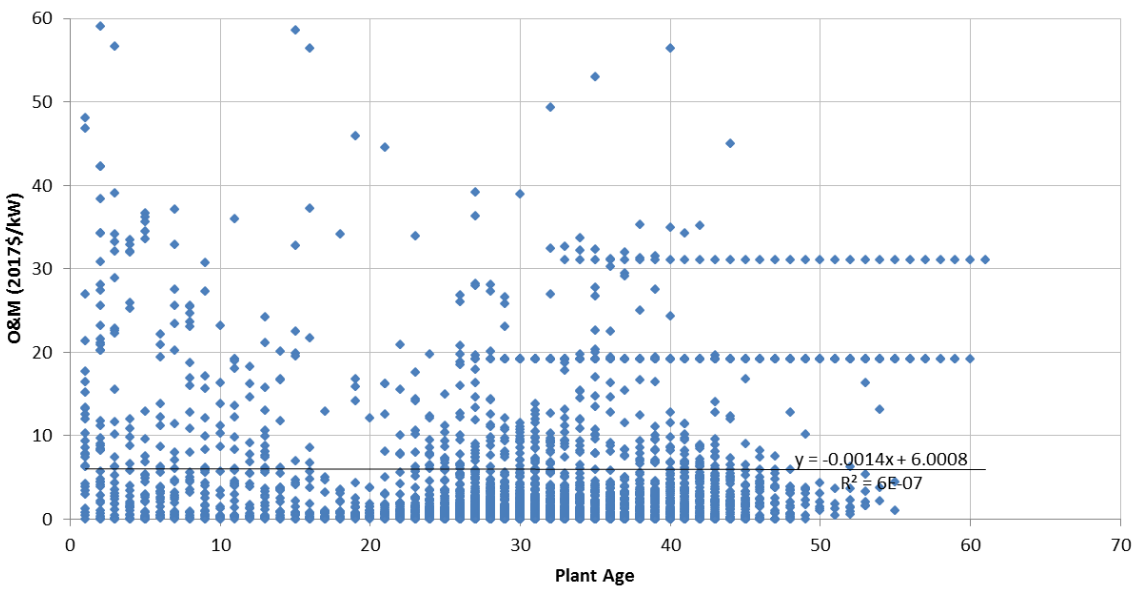
## OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 100 MW

The results of the regression analysis of O&M spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.966, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

**Table D-4 — Regression Statistics – CT O&M < 100 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 3,062 | | |
| **Simple Average ($/kW)** | 5.958 | | |
| **Intercept** | 6.001 | 5.5008 | 4.09E-08 |
| **Slope** | -0.001 | -0.0423 | 9.66E-01 |
| **$R^2$** | 0.00000 | | |

**Figure D-4 — Gas/Oil CT Dataset – O&M for Less than 100-MW Plant Size**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average \$/kW (years 1 - 20) = | Average \$/kW (years 21 - 40) = | Average \$/kW (years 41 - 80) = | **Average \$/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **< 100 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 \$/kW | 8.76 | 4.93 | 7.40 | **5.96** | 489 | 2,060 | 513 | **3,062** |
| Net Total Capex - 2017 \$/kW | 15.08 | 7.98 | 6.64 | **9.00** | 497 | 1,999 | 415 | **2,911** |
| Net Total O&M and Capex - 2017 \$/kW | 24.04 | 12.31 | 10.26 | **14.02** | 489 | 1,978 | 406 | **2,873** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

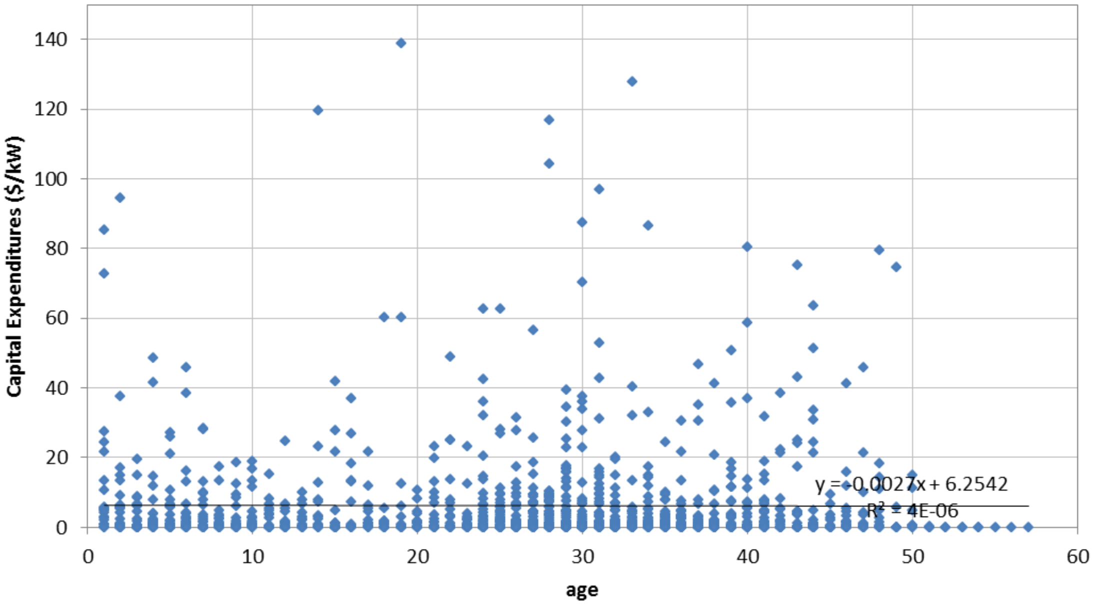
## CAPITAL EXPENDITURES – BETWEEN 100 MW AND 300 MW

The results of the regression analysis of CAPEX spending for CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.939, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table D-5 — Regression Statistics – CT CAPEX 100 MW to 300 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,350 | | |
| **Simple Average (\$/kW)** | 6.183 | | |
| **Intercept** | 6.254 | 6.0376 | 2.02E-09 |
| **Slope** | -0.003 | -0.0768 | 9.39E-01 |
| **$R^2$** | 0.00000 | | |

### Figure D-5 — Gas/Oil CT Dataset – CAPEX for Between 100-MW and 300-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 100 MW AND 300 MW

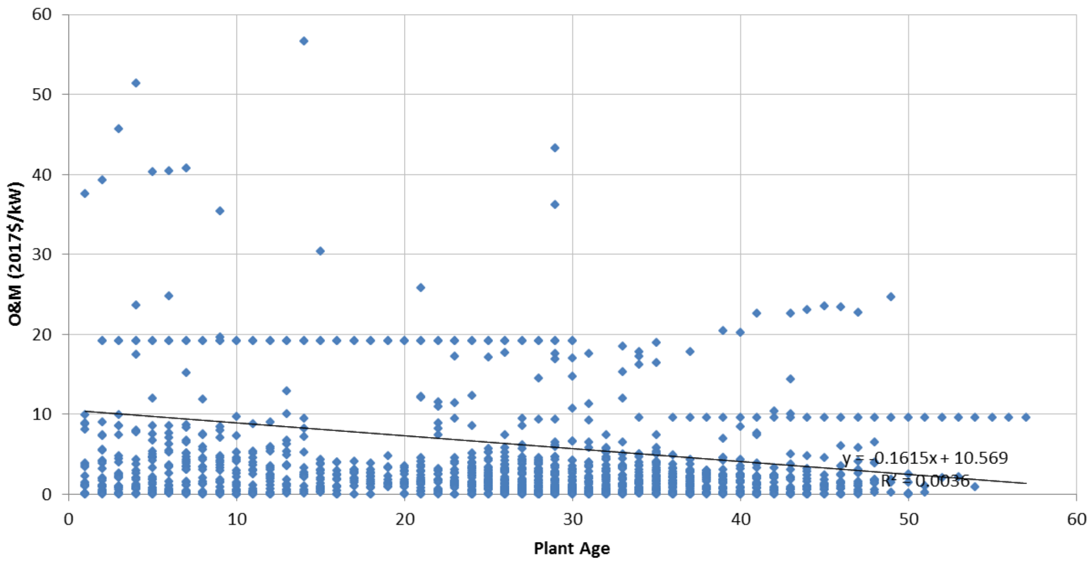
The results of the regression analysis of O&M spending for gas/oil CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.023, which is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 10.569 + (-0.162 × age)**

### Table D-6 — Regression Statistics – CT O&M 100 MW to 300 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,416 | | |
| **Simple Average ($/kW)** | 6.430 | | |
| **Intercept** | 10.569 | 5.1759 | 2.59E-07 |
| **Slope** | -0.162 | -2.2723 | 2.32E-02 |
| **$R^2$** | 0.00364 | | |

**Figure D-6 — Gas/Oil CT Dataset – O&M for Between 100-MW and 300-MW Plant Size**




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **100 MW - 300 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 9.97 | 5.18 | 3.24 | **6.43** | 442 | 794 | 180 | **1,416** |
| Net Total Capex - 2017 $/kW | 6.32 | 6.07 | 6.38 | **6.18** | 407 | 762 | 181 | **1,350** |
| Net Total O&M and Capex - 2017 $/kW | 15.14 | 9.09 | 9.66 | **10.98** | 402 | 759 | 180 | **1,341** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

## CAPITAL EXPENDITURES – GREATER THAN 300 MW

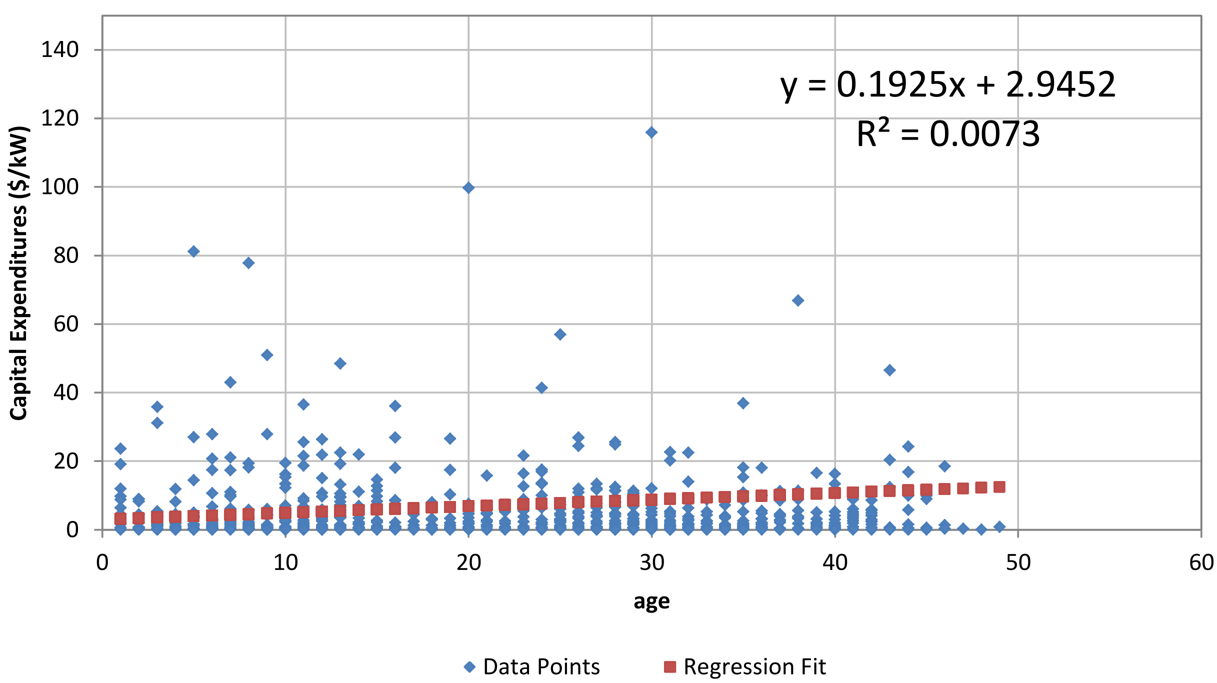
The results of the regression analysis of CAPEX spending for gas/oil CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.010, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

**Annual CAPEX spending in 2017 \$/kW-year = 2.945 + (0.193 × age)**

### Table D-7 — Regression Statistics – CT CAPEX > 300 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 909 | | |
| **Simple Average (\$/kW)** | 6.952 | | |
| **Intercept** | 2.945 | 1.6382 | 1.017E-01 |
| **Slope** | 0.193 | 2.5842 | 0.010 |
| **$R^2$** | 0.00731 | | |

### Figure D-7 — Gas/Oil CT Dataset – CAPEX for Greater than 300-MW Plant Size



## OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 300 MW

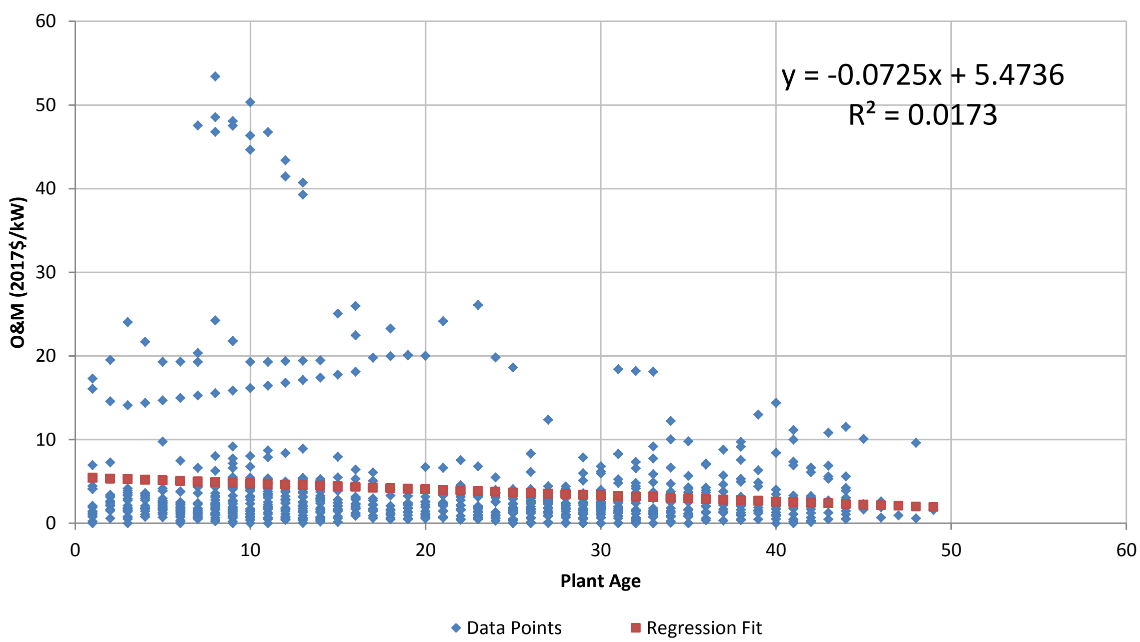
The results of the regression analysis of O&M spending for CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 5.474 + (-0.072 × age)**

### Table D-8 — Regression Statistics – CT O&M > 300 MW

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 938 | | |
| **Simple Average ($/kW)** | 3.994 | | |
| **Intercept** | 5.474 | 12.8980 | 3.75E-35 |
| **Slope** | -0.072 | -4.0612 | 5.29E-05 |
| **$R^2$** | 0.01732 | | |

### Figure D-8 — Gas/Oil CT Dataset – O&M for Greater than 300-MW Plant Size




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **> 300 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 5.03 | 2.78 | 3.46 | **3.99** | 488 | 396 | 54 | **938** |
| Net Total Capex - 2017 $/kW | 5.26 | 7.58 | 16.50 | **6.95** | 457 | 397 | 55 | **909** |
| Net Total O&M and Capex - 2017 $/kW | 9.30 | 10.38 | 20.11 | **10.42** | 451 | 396 | 54 | **901** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

# Appendix E. Regression Analysis – Conventional Hydroelectric

## CAPITAL EXPENDITURES – ALL PLANT SIZES

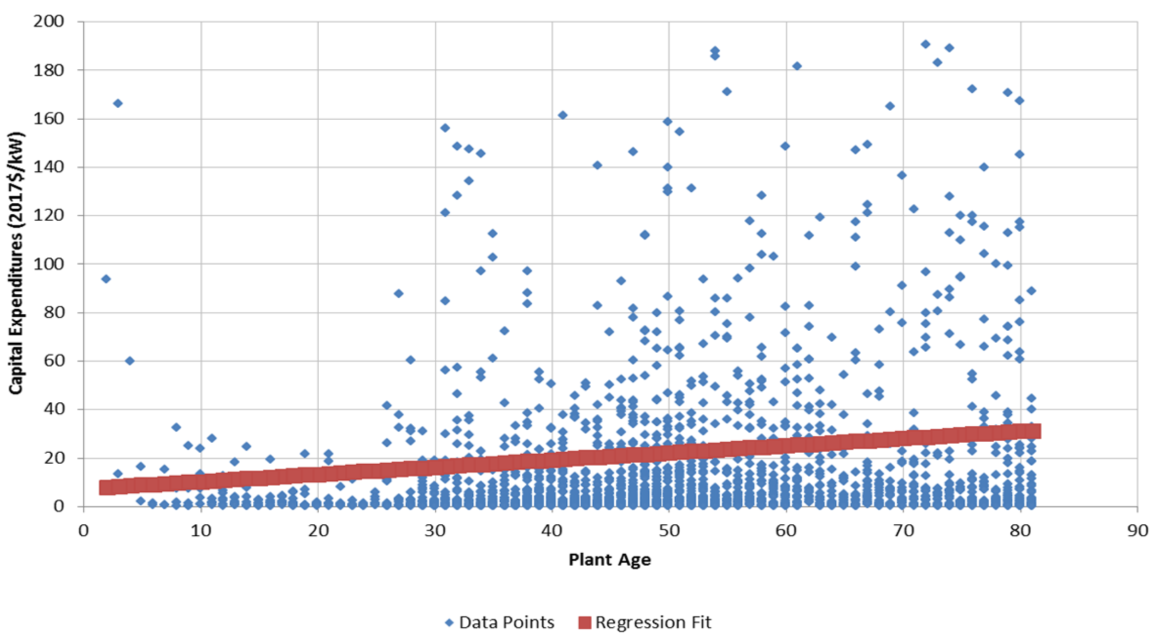
The results of the linear regression analysis of CAPEX spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

**Annual CAPEX spending in 2017 $/kW-year = 7.269 + (0.296 × age)**

### Table E-1 — Regression Statistics – Hydroelectric CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2180 | | |
| **Simple Average ($/kW)** | 21.999 | | |
| **Intercept** | 7.269 | 1.4681 | 1.42E-01 |
| **Slope** | 0.296 | 3.1441 | 1.69E-03 |
| **$R^2$** | 0.00452 | | |

### Figure E-1 — Conventional Hydroelectric Dataset – CAPEX for All MW Plant Sizes



## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

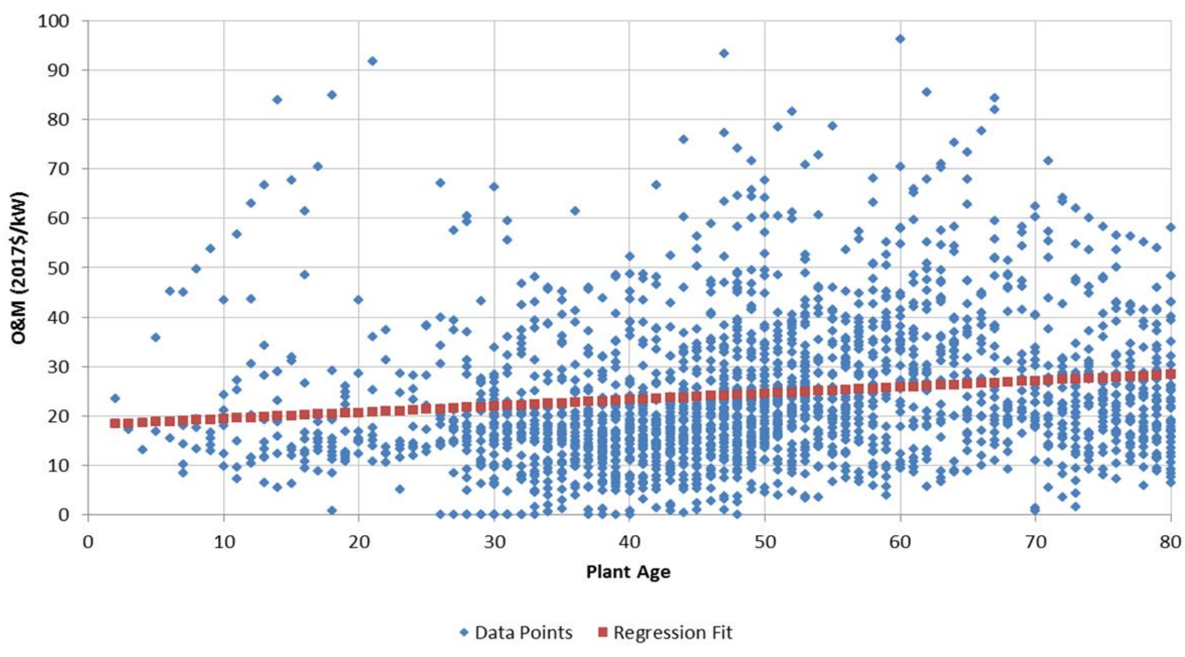
The results of the linear regression analysis of O&M spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 \$/kW-year = 22.360 + (0.073 × age)**

### Table E-2 — Regression Statistics – Hydroelectric O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,272 | | |
| **Simple Average (\$/kW)** | 24.473 | | |
| **Intercept** | 22.360 | 13.7360 | 3.92E-40 |
| **Slope** | 0.073 | 2.5053 | 1.24E-02 |
| **$R^2$** | 0.00492 | | |

### Figure E-2 — Conventional Hydroelectric – O&M for All MW Plant Sizes



# Appendix F. Regression Analysis – Pumped Hydroelectric Storage

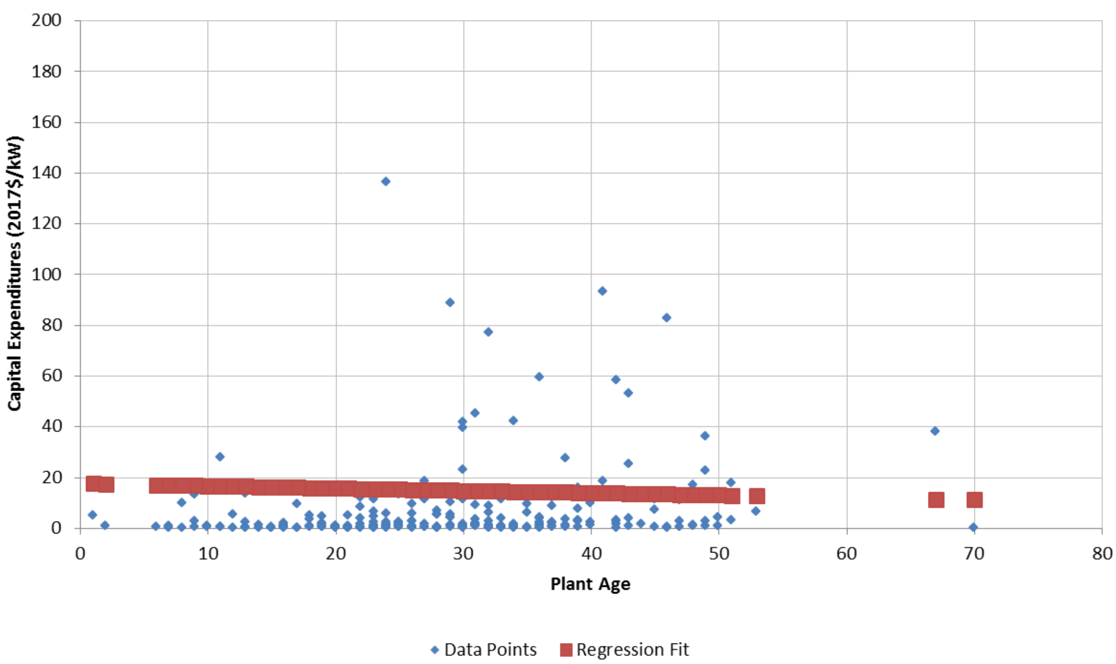
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

### Table F-1 — Regression Statistics – Pumped Hydroelectric CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 227 | | |
| **Simple Average ($/kW)** | 11.398 | | |
| **Intercept** | -6.907 | -0.4501 | 6.53E-01 |
| **Slope** | 0.743 | 1.2723 | 2.06E-01 |
| **$R^2$** | 0.01278 | | |

### Figure F-1 — Pumped Hydroelectric Dataset – CAPEX for All MW Plant Sizes




Note: Age coefficient in above regression equation is not statistically significant.

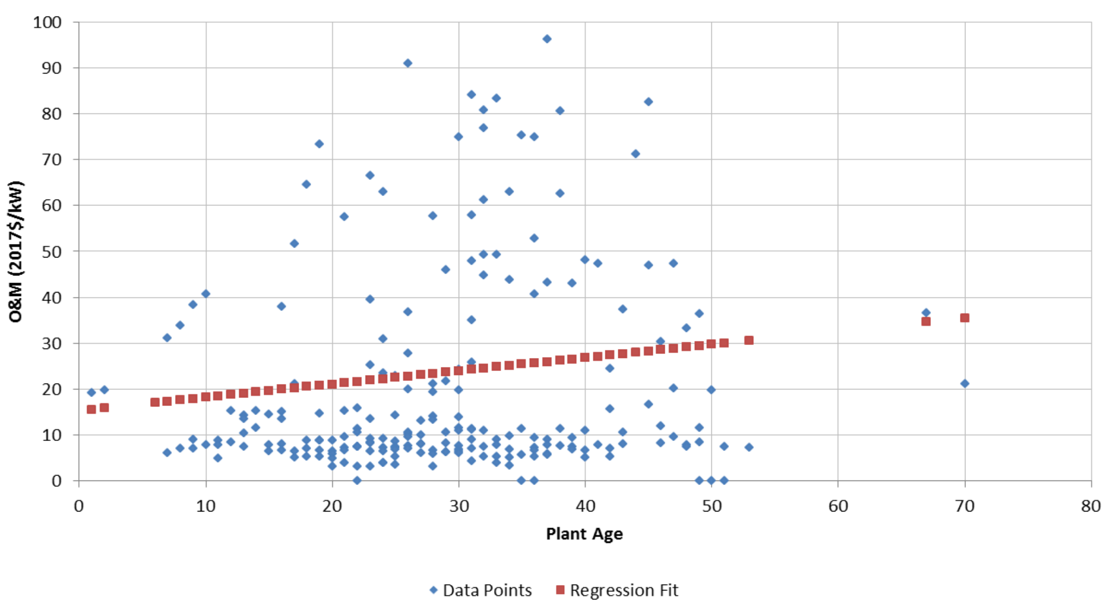
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

**Table F-2 — Regression Statistics – Pumped Hydroelectric O&M for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 226 | | |
| **Simple Average ($/kW)** | 23.634 | | |
| **Intercept** | 15.296 | 2.9021 | 4.08E-03 |
| **Slope** | 0.288 | 1.7010 | 9.03E-02 |
| **$R^2$** | 0.01275 | | |

**Figure F-2 — Pumped Hydroelectric – O&M for All Plant MW Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 18.97 | 23.41 | 31.00 | **23.63** | 50 | 140 | 36 | **226** |
| Net Total Capex - 2017 $/kW | 22.94 | 11.93 | 14.92 | **14.83** | 50 | 141 | 36 | **227** |
| Net Total O&M and Capex - 2017 $/kW | 41.91 | 35.34 | 45.92 | **38.46** | -- | -- | -- | -- |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing pumped hydroelectric storage plants are described in Section 8.

# Appendix G. Regression Analysis – Solar Photovoltaic

## CAPITAL EXPENDITURES

Annual CAPEX, labeled in FERC Form 1 as TCP, are broken down into subcategories, including:

- Land & Land Rights
- Structures & Improvements
- Reservoirs, Dams & Waterways
- Water Wheels
- Turbines & Generators
- Accessory Electric Equipment
- Equipment
- Asset Retirement Costs
- Roads, and Railroads & Bridges

These subcategories are based on traditional power generation technologies and have minimal applicability to solar PV. Expected CAPEX for solar PV, such as inverter replacement and repair or module replacement, are clearly not applicable to any of the categories listed in FERC Form 1.

In the FERC Form 1 data, only 10 of the solar PV sites had a breakdown of TCP into the above subcategories, with even fewer providing such a breakdown for more than one year. As discussed in Section 9, the year-over-year change in TCP is the sole source of annual CAPEX information in FERC Form 1. Of this data, Sargent & Lundy determined that a significant portion of it needed to be filtered out due to the following reasons:

- A negative change in the TCP between two consecutive years
- A change in the capacity of the plant greater than 20%
- A significant increase in TCP without a capacity increase
- Large unexplained fluctuations (e.g., negative to positive) in TCP from year to year
- Large gaps in annual data

After filtering out clearly suspect data, about one-third of the remaining data was for plants having only three years of data or less. In addition, many of the plants reported no changes in TCP, suggesting that most annual expenditures at those sites were being reported as O&M rather than being capitalized.

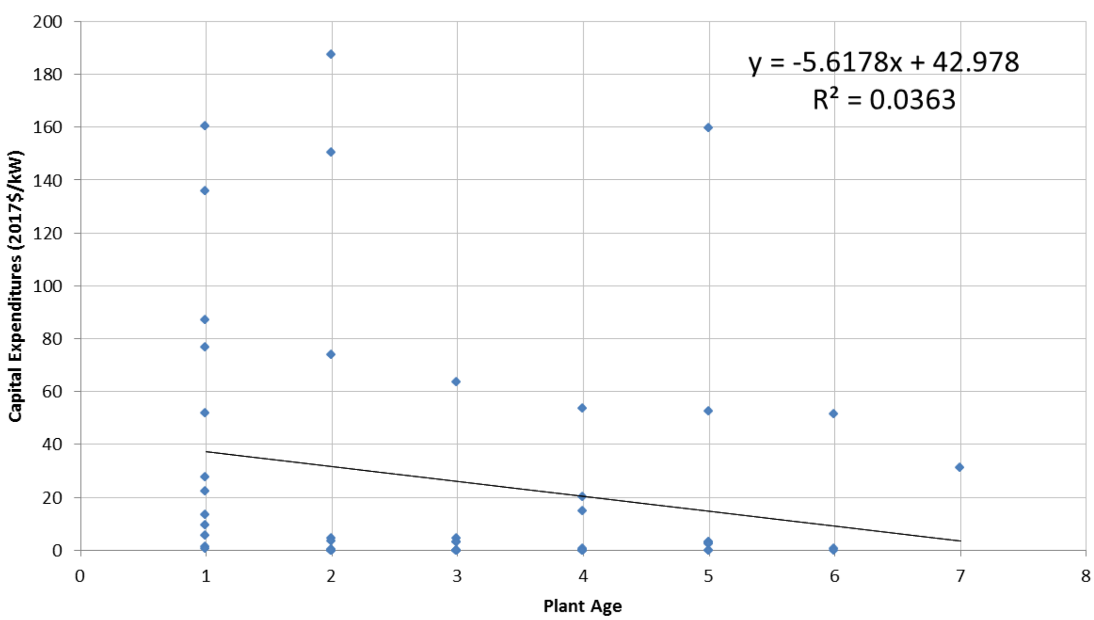
Thus, Sargent & Lundy had to rely on a limited dataset for solar PV consisting of 15 sites. The average change in TCP for these sites was approximately $26/kW-year. Based on the available FERC Form 1 information, it cannot be determined whether this change in TCP was due to typical CAPEX for solar PV, such as inverter or module replacement, or other factors.

The results of the linear regression analysis of CAPEX spending for solar PV plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.16, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). In addition, as indicated in the table below, there are a relatively small number of data points for CAPEX (less than 60 points). The average CAPEX across all years is approximately $26/kW-year (2017 dollars).

### Table G-1 — Regression Statistics – Solar PV CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 57 | | |
| **Simple Average ($/kW)** | 26.026 | | |
| **Intercept** | 42.978 | 3.2248 | 2.12E-03 |
| **Slope** | -5.618 | -1.4387 | 1.56E-01 |
| **$R^2$** | 0.03627 | | |

### Figure G-1 — Solar PV Dataset – CAPEX for All MW Plant Sizes




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment, inspecting modules for damage, inspecting mounting systems, and checking invertor settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

The total production cost, which is the sum of the total operating expense and total maintenance expense, was reported for slightly over half of the sites. Of the sites reporting, several sites only reported this data in certain years, leaving gaps in the data. Subcategories for operating costs and maintenance cost were provided in the FERC Form 1 data, but rarely was the reported data broken into subcategories.

Sargent & Lundy organized the FERC Form 1 data into two presentation formats. In the first format, the annual O&M cost was averaged across all years of the reported data to obtain the average annual O&M cost per plant. This resulted in approximately 60 data points. In the second format, the annual O&M cost was averaged across each year of operation. This resulted in approximately 200 data points. The average O&M cost results are not equal between the two presentation formats. Table G-2 provides a simple example of these differing results, using FERC Form 1 O&M data from three plants.

**Table G-2 — Example of Calculation Method Differences**

| | O&M Cost ($/kW-year) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Age (Years)** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | **13** | **14** | **15** | **Plant Average** |
| Example Plant 1 | 127.8 | 0.0 | 0.1 | 0.0 | - | - | - | - | - | - | - | - | - | - | - | 32.0 |
| Example Plant 2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Example Plant 3 | 32.2 | 15.3 | 24.8 | - | - | - | - | - | - | - | - | - | - | - | - | 24.1 |

| | |
|---|---|
| Example Average (All Data Points) | 9.1 |
| Example Average (of Plant Averages) | 18.7 |

In the example above, a single plant with more data points is able to sway the average O&M cost across the three plants. The values calculated below are based on averaged data points (i.e., a data point is the average annual O&M cost across the reported data for a given plant).

Figure G-2 and Figure G-3 show the average site O&M cost, expressed in \$/MWh, for sites with a capacity less than 5 MW and greater than 5 MW, respectively. In general, these figures show a high level of variability across sites, with smaller sites having a higher O&M cost per MWh produced. Several data points were for sites having very low capacity factors (less than 5%), which also results in higher O&M costs per MWh. For the sites greater than 5 MW, the average O&M cost was \$8.5/MWh. When expressed on the basis of cost per kW of capacity (see Figure G-4 and Figure G-5), the average O&M for sites greater than 5 MW was \$15/kW-year.

**Figure G-2 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (< 5 MW)**

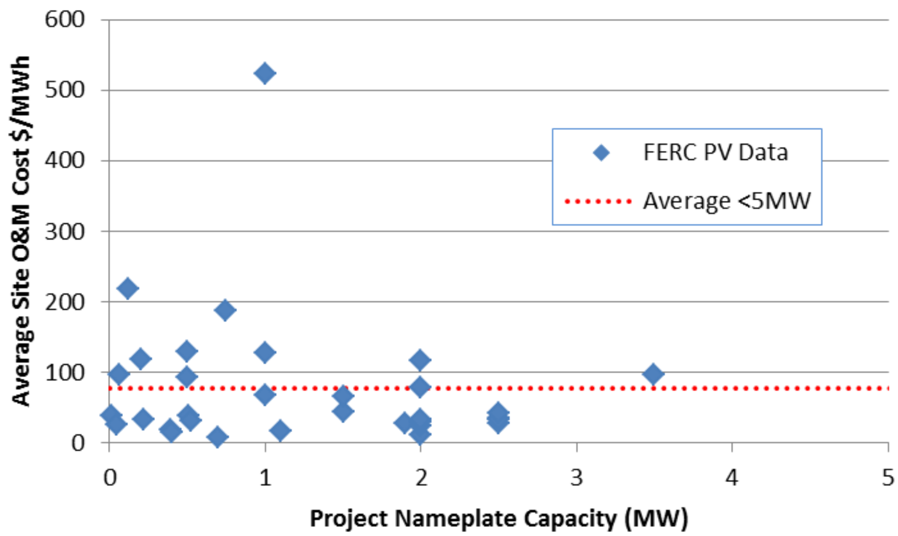


**Figure G-3 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (> 5 MW)**

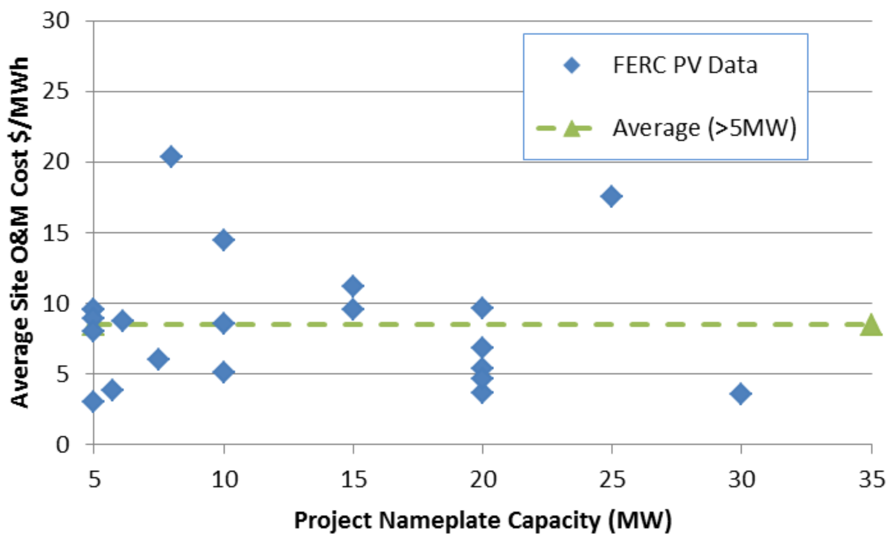



**Figure G-4 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (< 5 MW)**

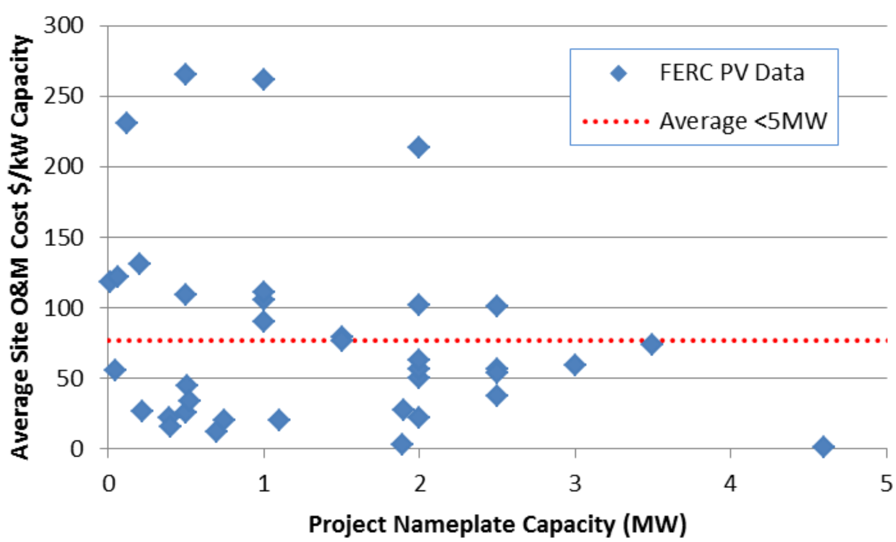
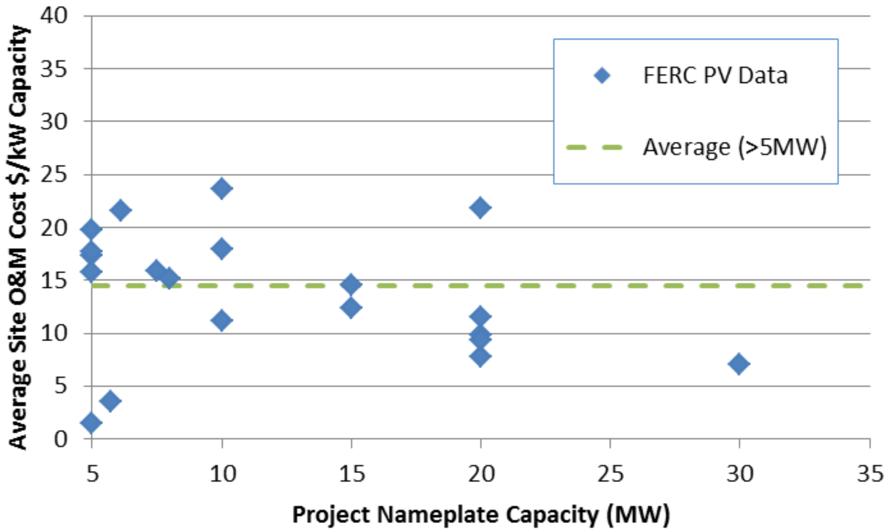
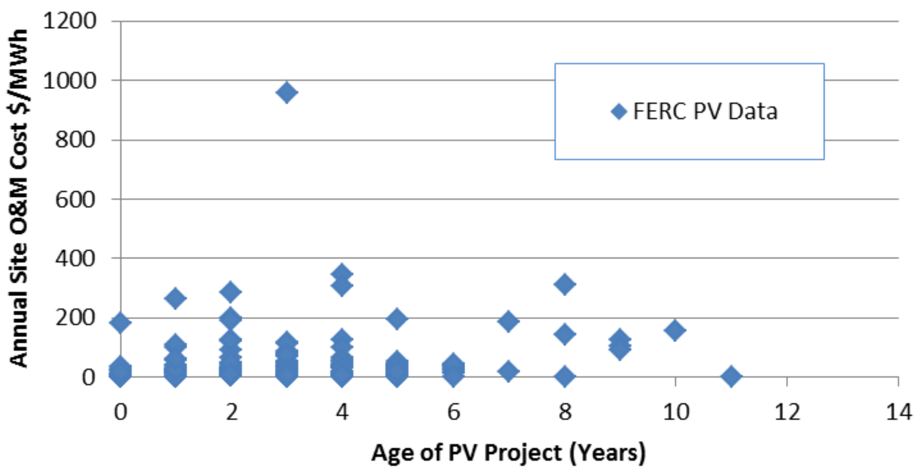


**Figure G-5 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (> 5 MW)**

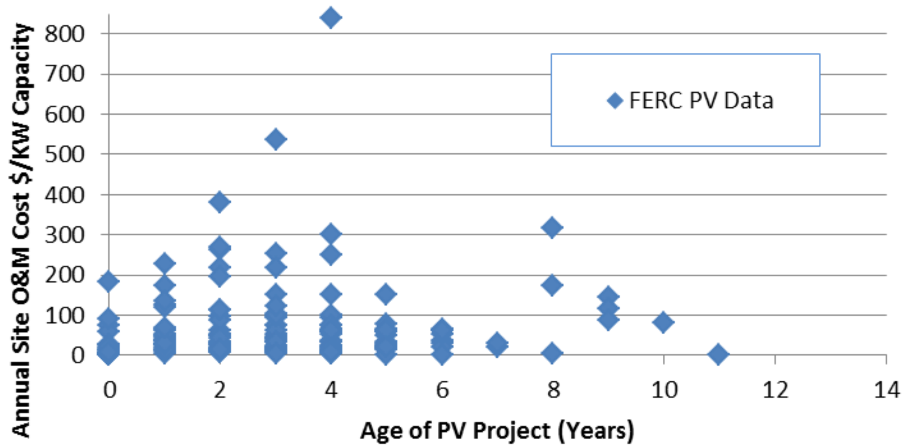



The figures below show the annual site O&M cost (in $/MWh and $/kW-year) versus the age of the project. In general, little correlation can be seen between age and O&M cost.

**Figure G-6 — Annual Site O&M Cost per MWh vs. Age of Project**



### Figure G-7 — Annual Site O&M Cost per kW-Year Capacity vs. Age of Project




Sargent & Lundy compiled O&M data from other sources in Table G-3 below for comparison against the FERC data. In general, the O&M costs in $/kW-year capacity are in the same range as the FERC data for sites over 5-MW capacity.

### Table G-3 — Summary of Industry O&M Cost Data for Solar PV

| O&M Cost Sources | O&M Cost $/kW-yr | Notes | Report Source Data Year |
|---|---|---|---|
| NREL & Sunshot | 15 | Fixed | 2015 |
| NREL & Sunshot | 18 | Single-Axis Tracking | 2015 |
| Sunshot + NREL | 20.5 | Good O&M | 2016 |
| Sunshot + NREL | 25.0 | Optimal O&M | 2016 |
| IRENA Power to Change | 10 | Minimum | 2015 |
| IRENA Power to Change | 18 | Maximum | 2015 |
| Utility Scale Solar | 17 | Overall | 2014 |
| Utility Scale Solar 2016 | 7 | Minimum | 2016 |
| Utility Scale Solar 2016 | 27 | Maximum | 2016 |
| Utility Scale Solar 2016 | 18 | Mean | 2016 |
| NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017 | 15.4 | Fixed LCOE Assumption | 2017 |
| NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018 | 18.5 | SAT LCOE Assumption | 2017 |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing solar PV plants are described in Section 9.

# Appendix H. Regression Analysis – Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

# Appendix I. Regression Analysis – Geothermal

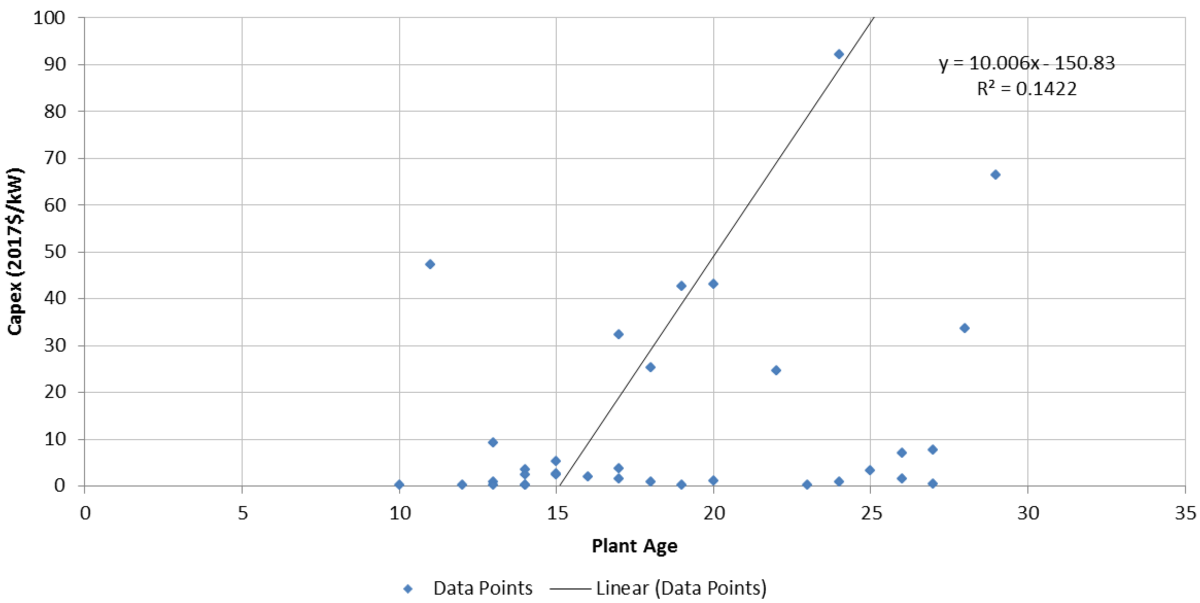
## CAPITAL EXPENDITURES

The results of the linear regression analysis of CAPEX spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Although the p-value is less than 0.05, the dataset is inconclusive because the intercept is negative due to no plants reporting data between ages and 0 and 10.

**Table I-1 — Regression Statistics – Geothermal CAPEX for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 36 | | |
| **Simple Average ($/kW)** | 40.948 | | |
| **Intercept** | -150.830 | -1.7907 | 8.23E-02 |
| **Slope** | 10.006 | 2.3736 | 2.34E-02 |
| **$R^2$** | 0.14215 | | |

**Figure I-1 — Geothermal Dataset – CAPEX for All MW Plant Sizes**



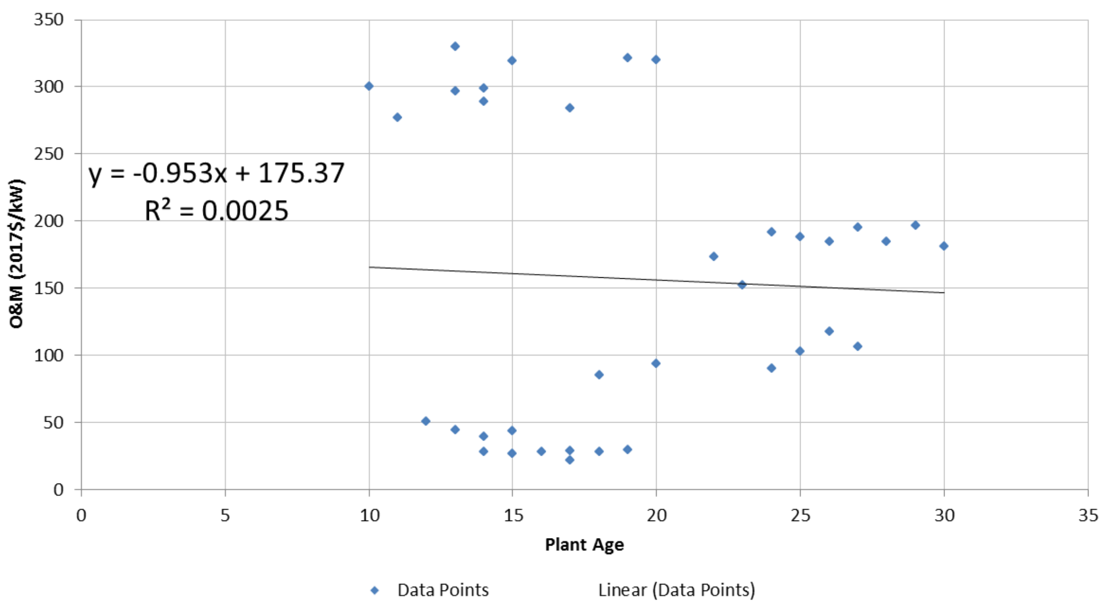
## OPERATIONS & MAINTENANCE EXPENDITURES

The results of the linear regression analysis of O&M spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.071, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

**Table I-2 — Regression Statistics – Geothermal O&M for All MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 36 | | |
| **Simple Average ($/kW)** | 157.103 | | |
| **Intercept** | 175.369 | 2.6984 | 1.08E-02 |
| **Slope** | -0.953 | -0.2930 | 7.71E-01 |
| **$R^2$** | 0.00252 | | |

**Figure I-2 — Geothermal Dataset – O&M for All MW Plant Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

### Table I-3 — Geothermal All MW Summary of Results

| | Average $/kW-yr (Years 1-5) | Average $/kW-yr (Years 6-10) | Average $/kW-yr (Years 11-15) | Average $/kW-yr (Years 16-20) | Average $/kW-yr (Years 21-25) | Average $/kW-yr (Years 26-30) | Average $/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (Years 11-15) | Data Points (Years 16-20) | Data Points (Years 21-25) | Data Points (Years 26-30) | Data Points (All Years) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | | | | | | | |
| Net Total O&M – 2017 $/kW-yr | -- | 300.62 | 170.44 | 124.24 | 149.97 | 166.77 | **157.10** | -- | 1 | 12 | 10 | 6 | 7 | **36** |
| Net Total CAPEX – 2017 $/kW-yr | -- | -- | 72.05 | 30.16 | 27.64 | 114.45 | **40.94** | -- | 1 | 12 | 10 | 6 | 7 | **36** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing geothermal plants are described in Section 11.

# Appendix J. Regression Analysis – Wind

## CAPITAL EXPENDITURES

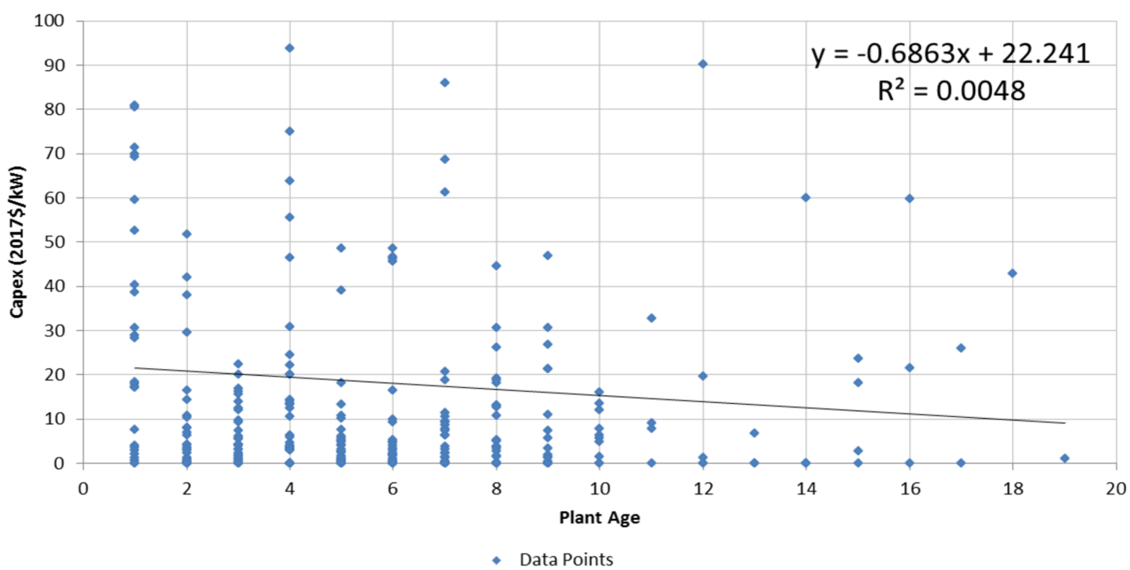
### *Full Dataset*

The results of the linear regression analysis of CAPEX spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table J-1 — Regression Statistics – Wind CAPEX for All MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 310 | | |
| **Simple Average ($/kW)** | 18.285 | | |
| **Intercept** | 22.241 | 5.7807 | 1.82E-08 |
| **Slope** | -0.686 | -1.2194 | 2.24E-01 |
| **$R^2$** | 0.00480 | | |

**Figure J-1 — Wind Dataset – CAPEX for All MW Plant Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

**Table J-2 — Wind All MW Summary of Results**

| | Average \$/kW-yr (Years 1-5) | Average \$/kW-yr (Years 6-10) | Average \$/kW-yr (Years 11-15) | Average \$/kW-yr (Years 16-20) | Average \$/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (Years 11-15) | Data Points (Years 16-20) | Data Points (All Years) |
|---|---|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | | | |
| Net Total CAPEX – 2017 \$/kW-yr | 21.06 | 10.97 | 32.62 | 21.60 | **18.29** | 168 | 112 | 23 | 7 | **310** |

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

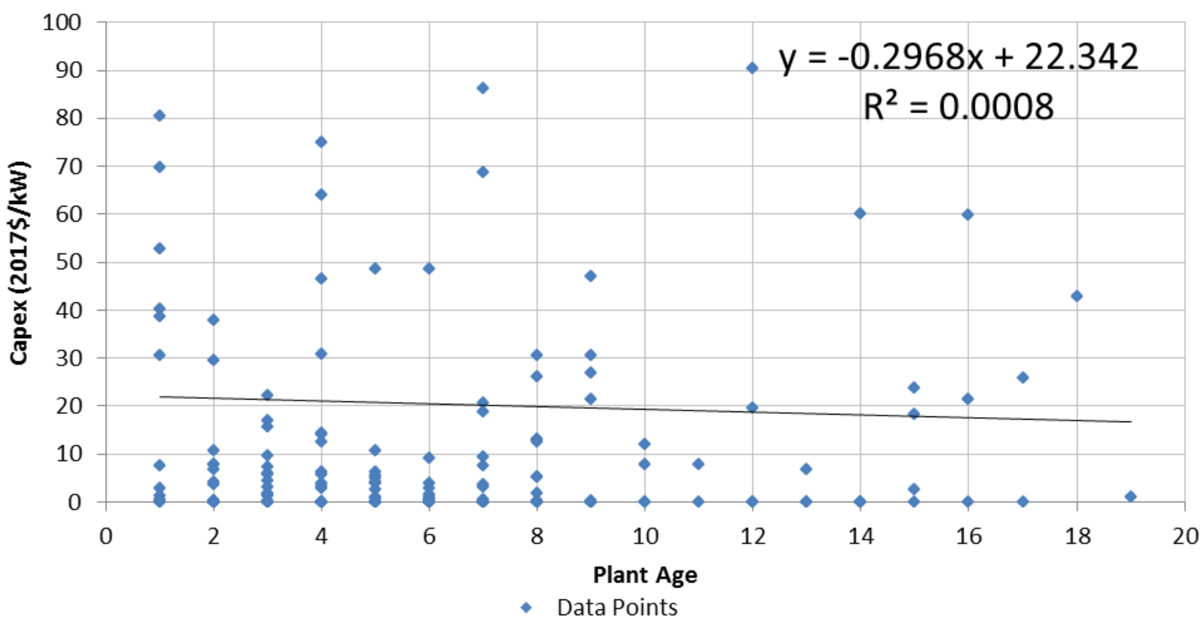
### *0-100 MW*

The results of the linear regression analysis of CAPEX spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.706, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, a more appropriate predictor of CAPEX spending for this dataset is a simple average by plant age band, as discussed in Section 12.

**Table J-3 — Regression Statistics – Wind CAPEX for 0-100 MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 174 | | |
| **Simple Average (\$/kW)** | 20.483 | | |
| **Intercept** | 22.342 | 3.7750 | 2.20E-04 |
| **Slope** | -0.297 | -0.3779 | 7.06E-01 |
| **$R^2$** | 0.00083 | | |

### Figure J-2 — Wind Dataset – CAPEX for 0-100-MW Plant Sizes




Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

### Table J-4 — Wind < 100-MW Summary of Results

| | Average $/kW-yr (Years 1-5) | Average $/kW-yr (Years 6-10) | Average $/kW-yr (Years 11-15) | Average $/kW-yr (Years 16-20) | Average $/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (Years 11-15) | Data Points (Years 16-20) | Data Points (All Years) |
|---|---|---|---|---|---|---|---|---|---|---|
| **< 100 MW, All Capacity Factors** | | | | | | | | | | |
| Net Total CAPEX – 2017 $/kW-yr | 22.83 | 11.62 | 35.35 | 21.60 | **20.48** | 89 | 58 | 20 | 7 | **174** |

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

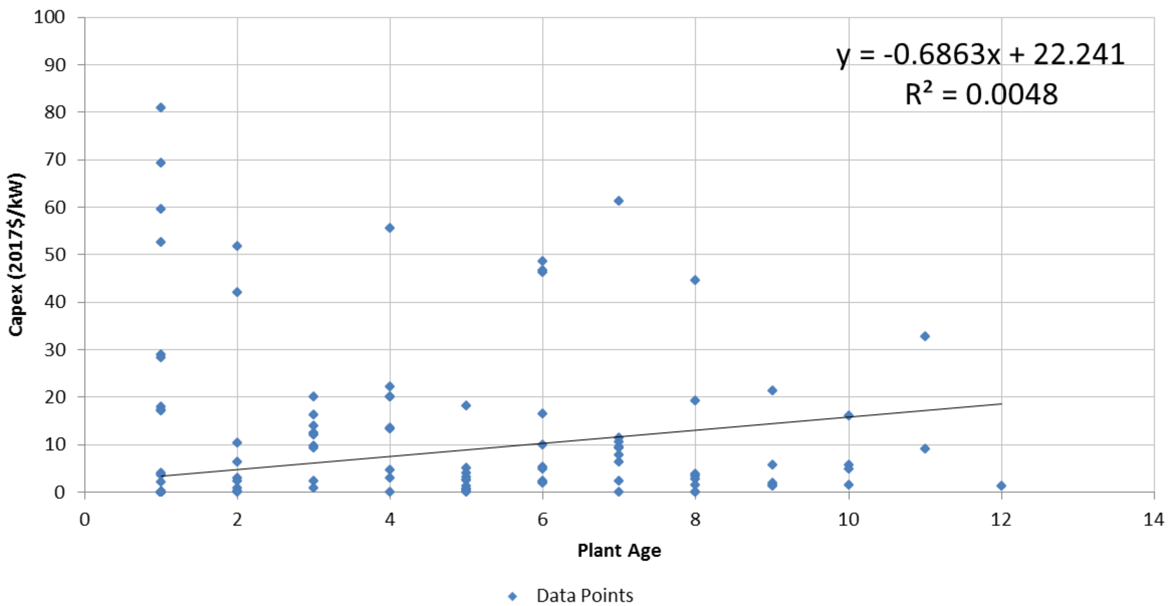
### *100-200 MW*

The results of the linear regression analysis of CAPEX spending for wind plants between 100 MW and 200 MW are summarized in the table below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table J-5 — Regression Statistics – Wind CAPEX for 100-200 MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 310 | | |
| **Simple Average ($/kW)** | 16.935 | | |
| **Intercept** | 22.241 | 5.7807 | 1.82E-08 |
| **Slope** | -0.686 | -1.2194 | 2.24E-01 |
| **$R^2$** | 0.00480 | | |

**Figure J-3 — Wind Dataset – CAPEX for 100-200-MW Plant Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

**Table J-6 — Wind 100-200-MW Summary of Results**

| | Average $/kW-yr (Years 1-5) | Average $/kW-yr (Years 6-10) | Average $/kW-yr (Years 11-15) | Average $/kW-yr (Years 16-20) | Average $/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (Years 11-15) | Data Points (Years 16-20) | Data Points (All Years) |
|---|---|---|---|---|---|---|---|---|---|---|
| **100 - 200 MW, All Capacity Factors** | | | | | | | | | | |
| Net Total CAPEX – 2017 $/kW-yr | 20.36 | 12.20 | 14.41 | -- | **16.93** | 52 | 36 | 3 | -- | **91** |

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

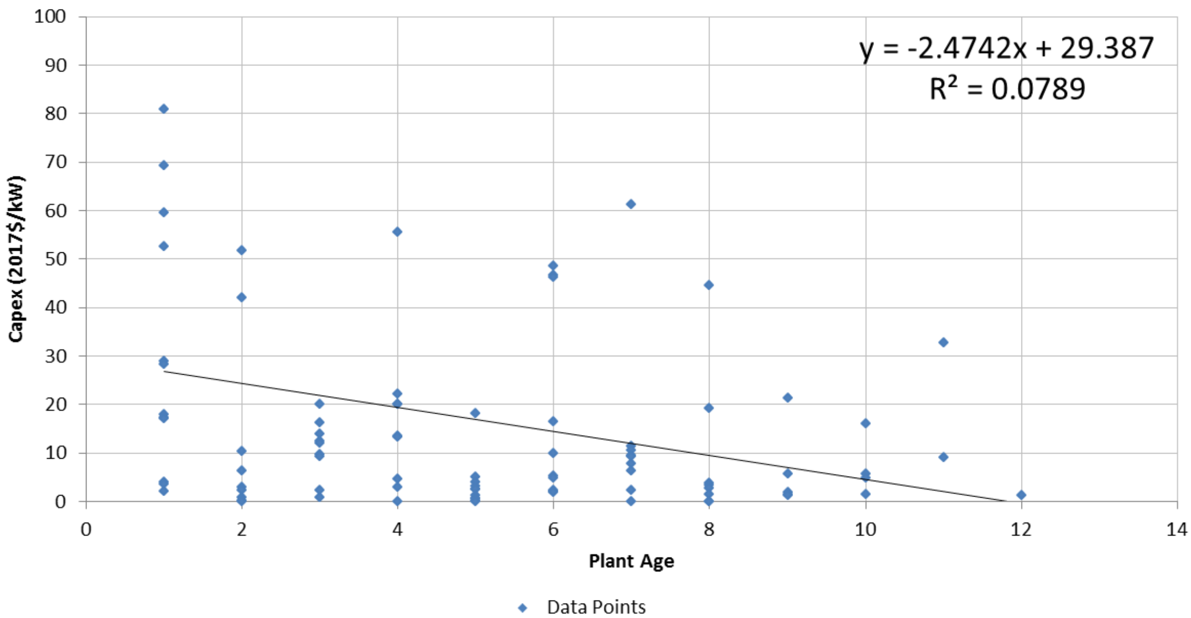
### *Greater than 200 MW*

The results of the linear regression analysis of CAPEX spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.006, which is less than 0.05, the dataset does support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, a visual inspection of the data in the graph below shows that there are a limited number of data points over 10 years, which may be skewing the regression.

**Table J-7 — Regression Statistics – Wind CAPEX for Greater than 200 MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 91 | | |
| **Simple Average ($/kW)** | 16.935 | | |
| **Intercept** | 29.387 | 5.6538 | 1.87E-07 |
| **Slope** | -2.474 | -2.7612 | 6.99E-03 |
| **$R^2$** | 0.07891 | | |

### Figure J-4 — Wind Dataset – CAPEX for Greater than 200-MW Plant Sizes




The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

### Table J-8 — Wind Greater than 200-MW Summary of Results

| | Average $/kW-yr (Years 1-5) | Average $/kW-yr (Years 6-10) | Average $/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (All Years) |
|---|---|---|---|---|---|---|
| **> 200 MW, All Capacity Factors** | | | | | | |
| Net Total CAPEX – 2017 $/kW-yr | **16.61** | **8.65** | **13.48** | 31 | 20 | **51** |

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

## OPERATIONS & MAINTENANCE EXPENDITURES

### *Full Dataset*

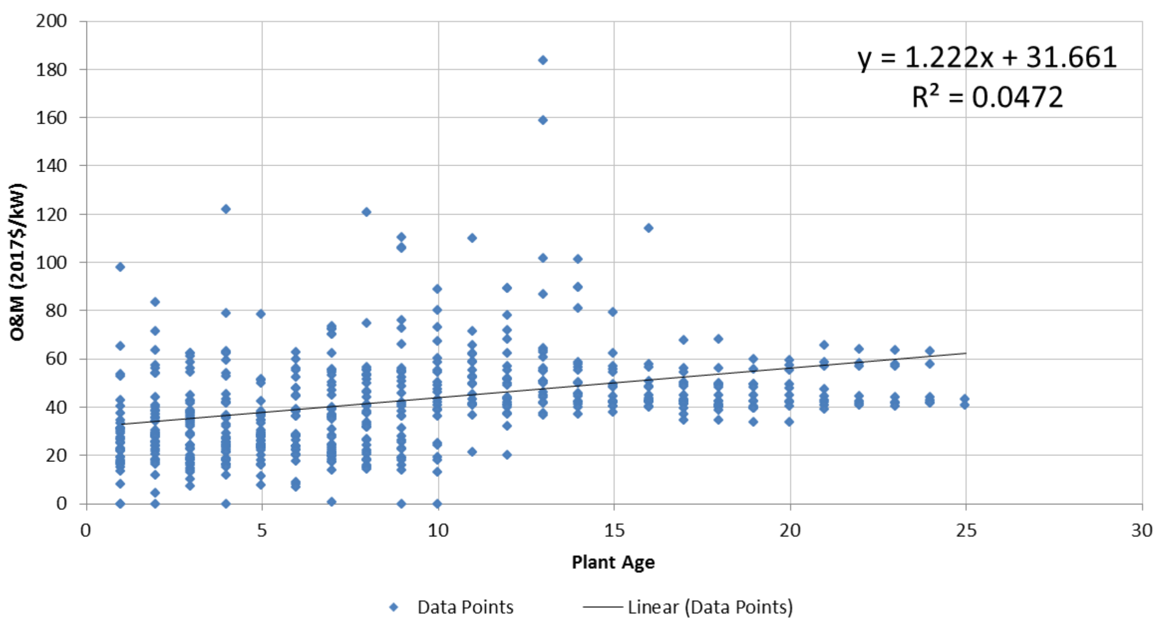
The results of the linear regression analysis of O&M spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 \$/kW-year = 31.661 + (1.222 × age)**

**Table J-9 — Regression Statistics – Wind O&M for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 580 | | |
| **Simple Average (\$/kW)** | 42.680 | | |
| **Intercept** | 31.661 | 12.7763 | 4.24E-33 |
| **Slope** | 1.222 | 5.3515 | 1.26E-07 |
| **$R^2$** | 0.04721 | | |

**Figure J-5 — Wind Dataset – O&M for All MW Plant Sizes**



### *0-100 MW*

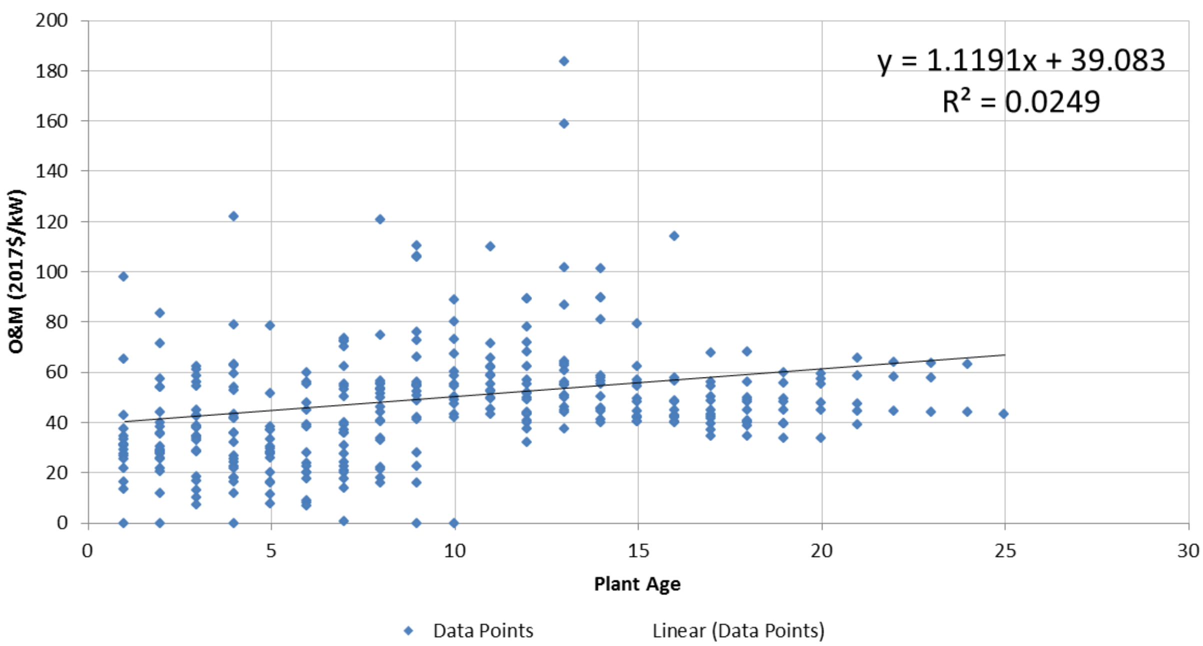
The results of the linear regression analysis of O&M spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.003, which is less than 0.05, the dataset age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 39.083 + (1.119 × age)**

### Table J-10 — Regression Statistics – Wind O&M for 0-100 MW

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 339 | | |
| **Simple Average ($/kW)** | 49.888 | | |
| **Intercept** | 39.083 | 9.0574 | 1.10E-17 |
| **Slope** | 1.119 | 2.9310 | 3.61E-03 |
| **$R^2$** | 0.02486 | | |

### Figure J-6 — Wind Dataset – O&M for 0-100-MW Plant Sizes



### *100-200 MW*

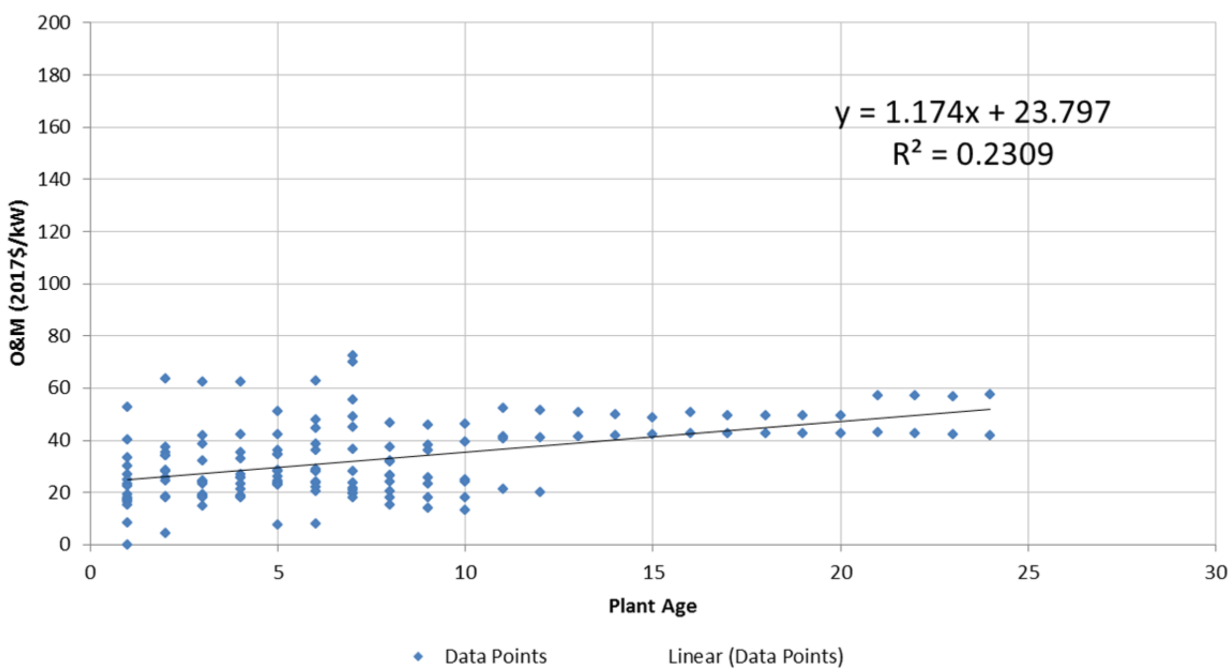
The results of the linear regression analysis of O&M spending for wind plants between 100 MW and 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 \$/kW-year = 23.797 + (1.174 × age)**

**Table J-11 — Regression Statistics – Wind O&M for 100-200 MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 147 | | |
| **Simple Average (\$/kW)** | 35.645 | | |
| **Intercept** | 23.797 | 14.1919 | 3.27E-29 |
| **Slope** | 1.174 | 6.5971 | 7.33E-10 |
| **$R^2$** | 0.23086 | | |

**Figure J-7 — Wind Dataset – O&M for 100-200-MW Plant Sizes**



### *Greater than 200 MW*

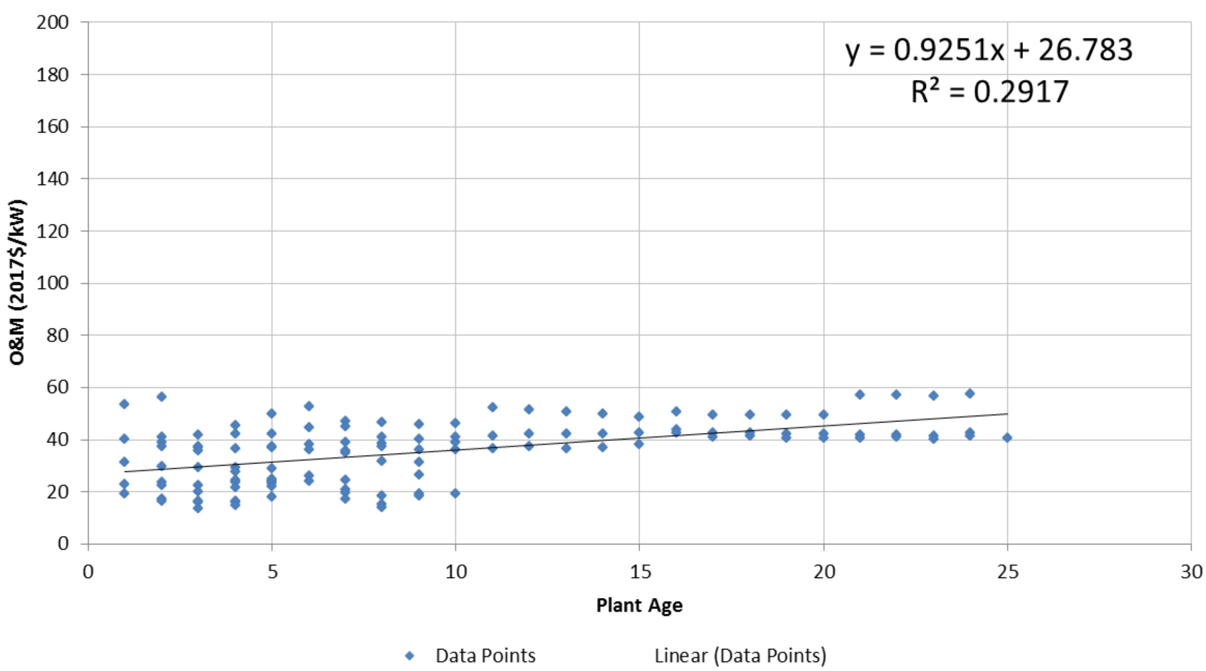
The results of the linear regression analysis of O&M spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 \$/kW-year = 26.783 + (0.925 × age)**

**Table J-12 — Regression Statistics – Wind O&M Greater than 200 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 124 | | |
| **Simple Average (\$/kW)** | 35.645 | | |
| **Intercept** | 26.783 | 17.5334 | 3.90E-35 |
| **Slope** | 0.925 | 7.0885 | 9.55E-11 |
| **$R^2$** | 0.29171 | | |

**Figure J-8 — Wind Dataset – O&M for Plant Sizes Greater than 200 MW**



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-26-21 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-163
Trump Advisor Says Electricity Customers Pay for 202(c) Orders

Story by Laura Sanicola • 1w • 3 min read

IN THIS ARTICLE

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The J.H. Campbell coal-fired power plant in Michigan. Consumers Energy had planned to retire the plant in 2025, but President Trump ordered it to keep operating.
© Jim West / UCG / Getty Images

A Trump administration official said Wednesday that efforts to keep coal-fired power plants running beyond their planned retirement dates will ultimately be paid for by electricity customers.

Federal efforts to block coal plant retirements aim to preserve grid reliability amid a surge in electricity demand driven by data centers and artificial intelligence, said Peter Lake, a member of the White House's National Energy Dominance Council, speaking at the American Enterprise Institute's "Powering Prosperity and the New Electricity Economy" conference in Washington.



"All costs end up on ratepayers," Lake said, responding to a question about who pays when utilities are required by the federal government to keep coal plants online after having invested billions of dollars in replacement power generation.

He added that industrial customers typically bear a larger share of those costs, equivalent to about 60%. But it depends on the utility, their generation makeup, and how rate structures allocate expenses based on load size and peak demand.

The Trump administration has so far prevented dozens of coal units from retiring, invoking emergency authorities and directing federal agencies to intervene in power markets. Officials say the U.S. grid cannot afford to lose generation as electricity demand accelerates faster than expected.

The administration has also framed its coal policy as an affordability and reliability measure, aimed at avoiding what Lake said could be $34 billion to $40 billion in replacement costs if operating coal plants were allowed to retire before new dispatcheable resources are in place.

**Related video**: Why renewables did not cut bills (Simon Clark)

Simon Clark

Why renewables did not cut bills

Government estimates call for roughly 100 gigawatts of new power by 2030, a figure Lake compared with adding "California plus two New Yorks" to the grid in less than five years.

"Yes, we need coal. We need gas. We need batteries. Anything with an answer," Lake said.

Coal is getting a boost from AI power and industrial demand. Several utilities, including Duke Energy and some subsidiaries of Southern Company, revised plans to retire some coal units after forecasting sharp increases in demand from data centers and advanced manufacturing. The changes were approved through state-regulated processes.

But utilities say that being forced to keep some coal plants open is upending years of state-approved planning.

For example, the Michigan-based Campbell coal plant, owned by CMS Energy, was forced by the Trump administration to continue operating into 2026 after being scheduled to retire in 2025, costing about $615,000 a day, according to company filings. The state utility running the plant, Consumers Energy, had already invested in replacement gas generation, renewable contracts, and grid upgrades.





Consumers Energy warned that extending Campbell's operations will adds millions of dollars in incremental fuel, maintenance, and staffing costs that weren't contemplated in approved rates, according to regulatory filings.

Consumers in regulated energy markets may be hit hardest as coal plants stay open longer than planned. A utility that voluntarily plans to delay a plant retirement often gets approval from regulators in a deal that includes freezing rates for consumers and special tariffs that shift costs toward large industrial users like data centers.

That framework can collapse when Washington forces plants to keep operating. When a plant is kept online after replacement assets are already in the rate base, customers effectively pay twice—once for the new plant, and again for the old one.

Some utilities are trying to manage rising AI power needs without passing along costs to households. In Louisiana and parts of the Midwest, for instance, utilities have negotiated special large-load tariffs and contract terms with data-center customers that include higher base rates, upfront infrastructure contributions, and curtailment provisions during grid stress.

Still, some energy experts say the administration's plans to delay coal retirements may be counterproductive and obscure the more pressing problem: permitting delays to upgrade the grid.

"Mandating that an old power plant operate isn't consistent with a market-based approach," said Rob Gramlich, president of Grid Strategies LLC, at the AEI conference, noting that tens of gigawatts of approved generation remain stalled in interconnection queues due to permitting and transmission constraints.

A study by Grid Strategies, a consultancy funded partly by environmental groups including the Sierra Club, found that the administration's plan to stop fossil fuel plants from closing could cost ratepayers $3.1 to $5.9 billion a year.

Write to Laura Sanicola at laura.sanicola@barrons.com



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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-26-21 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-164
Colorado Commission Decision No. C24-0052

Decision No. C24-0052

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 21A-0141E

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

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**PHASE II DECISION: (1) ADDRESSING RESOURCE SELECTION AND THEREBY MODIFYING PUBLIC SERVICE'S CLEAN ENERGY PLAN; (2) ADDRESSING THE ADDITIONAL TRANSMISSION INVESTMENTS IDENTIFIED IN PHASE II; (3) ESTABLISHING PERFORMANCE INCENTIVE MECHANISMS FOR UTILITY-OWNED GENERATION; (4) ADDRESSING THE 2024 JUST TRANSITION SOLICITATION; AND (5) ADDRESSING RELATED MATTERS**

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Mailed Date: January 23, 2024
Adopted Date: December 6, 13, 20, 2023

**TABLE OF CONTENTS**

# I. BY THE COMMISSION

## A. Statement

1. In accordance with § 40-2-125.5(4), C.R.S., the electric resource plan (ERP) filed by Public Service Company of Colorado (Public Service or the Company) on March 31, 2021, includes a Clean Energy Plan (CEP) to reduce the Company's carbon dioxide (CO2) emissions by a target of 80 percent by 2030 as compared to 2005 levels. As set out in Decision No. C22-0459 (the Phase I Decision)[1] and Decision No. C22-0559 (addressing applications for rehearing, reargument, or reconsideration)[2] the Commission approved certain elements of the Company's CEP, including the Coal Action Plan that transitions Public Service away from its remaining coal facilities. The Commission also authorized Public Service to use Phase II of this Proceeding to further implement the requirements for approval of a CEP such that the Commission could continue evaluation of, among other things, the additional clean energy plan activities, the actions and investments projected to achieve compliance with the clean energy targets in § 40-2-125.5(3)(a)(I) and (3)(a)(II), and whether the CEP is in the public interest and consistent

[1]Issued August 3, 2022.
[2] Issued September 21, 2022.

with the clean energy target in § 40-2-125.5(3)(a)(I). The Commission's decisions in Phase I and Phase II of this ERP proceeding thus implement a bold clean energy policy that helps avoid the worst impacts of climate change while allowing Coloradoans to enjoy the benefits of reliable clean energy at an affordable cost.

2. Throughout the course of Phase II, Public Service showcased its preferred resource portfolio of new utility resources to be acquired through 2027 and, in response to party and public comments, its updated preferred portfolio of resources. In accordance with the Commission's Phase I directives, the Company also presented numerous alternate portfolios for consideration. Although the Company's preferred resource portfolio[3] projects sufficient emission reductions to exceed statutory requirements, comments point out that not only might these projected reductions in emissions be overstated, but that the costs to customers would be significant – pointing to, among other major concerns, billions of dollars in modeled transmission investment changes between Phase I and II, and significant utility ownership in gas resources presented in the Company's updated preferred plan.

3. Building on our determinations in Phase I, we find that modifying the Company's CEP by selecting an alternative resource portfolio (the Alternative Portfolio)[4] is necessary considering statutory and public interest concerns.

4. The Alternative Portfolio exceeds Colorado's goals in emission reductions and protects reliability of the electrical system, according to the Company's analysis. At the same time,

[3] As detailed below, in the 120-Day Report, Public Service presented its Preferred Portfolio, and this Preferred Portfolio is what comments from intervenors address. In its Response Comments, the Company presents an Updated Preferred Portfolio. Apart from a few minor modifications (*e.g.* replacing a wind project with a different wind project) the Updated Preferred Portfolio and the Preferred Portfolio are identical. The benefits of the Alternative Portfolio set forth throughout this Phase II decision apply both to the Preferred Portfolio and the Updated Preferred Portfolio.

[4] As discussed below, the Alternative Portfolio is the Inverse 1324 ($0CO2) Plan that Public Service included in the 120-Day Report. (*See* 120-Day Report (Appendix S) Rev. 1, p. 26).

the Alternative Portfolio—which includes fewer new utility-owned resources than the Company's preferred resource portfolio and is thus better tailored to the developing capabilities of the Company's system—will reduce costs to customers, especially considering factors such as the curtailment of generated renewable energy.

5. This case propels Colorado's transition towards greater reliance on renewable resources, takes massive strides towards emission reductions, and continues on a path towards 100 percent clean energy resources; however, the Company maintains that system reliability currently requires at least some new natural gas-fired generation resources. Like the Company's updated preferred portfolio, the Alternative Portfolio includes nearly half the amount of gas resources predicted in the Phase I Settlement modeling, which was supported by a majority of parties with diverse interests, including some environmental advocates.[5] Moreover, and unlike the Company's updated preferred plan, the Alternative Portfolio better allows for technological advancements and flexibility by deferring certain resource acquisitions, reducing the amount of Company-owned gas resources, and significantly increasing the amount of storage on the electrical system. For similar reasons, the Alternative Portfolio creates the opportunity to better optimize transmission upgrades during resource procurement in future proceedings.

6. Particularly given the billions of dollars in discrepancies of modeled transmission costs, granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio with the Phase I authorizations also allows us to better support Colorado customers and communities. Through directed modeling and filing considerations, we include further direction to support transitioning communities through the 2024 Just Transition Solicitation. As we remain dedicated to supporting the economic changes facing our state's

[5] Phase I Settlement (Attachment D), p. 2.

transitioning communities, optionality and opportunity through ongoing, robust, competitive bidding is essential to continue selecting optimal resources to support Colorado's needs. In recognition that affordability of energy bills remains a significant focus, we also include direction on performance incentive mechanisms that further incentivize Public Service to reduce the costs of the new Company-owned generation and promotes fairness and transparency within the competitive bidding process.

7. On balance, the Phase I and Phase II Decisions together provide a measured approach to reliability and cost considerations, while taking exponential strides towards a clean energy future that supports Colorado citizens. These decisions propel the Company towards an 86 percent reduction in emissions by 2030 as well as the goal of providing its customers with energy from 100 percent clean energy resources by 2050.

8. Thus, through this Decision we find that modification of the proposed CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest. Consistent with the Phase I Decision and determinations in this Phase II order, we direct Public Service to pursue this modified CEP and its Alternative Portfolio of resources with further due diligence and contract negotiations and to file applications for Certificates of Public Convenience and Necessity (CPCNs) for all Company-owned generation resources arising from the modified CEP. We further direct that all Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM set forth below.

9. In addition, we make several directives regarding transmission investments as well as future proceedings, including the 2024 Just Transition Solicitation proceeding and the

application Public Service will file regarding the attribution of costs between the CEP rider (CEPR) and the Renewable Energy Standard Adjustment (RESA).

## B. Discussion

### 1. Electric Resource Planning

10. The Commission's ERP Rules, set forth at 4 *Code of Colorado Regulations* (CCR) 723-3-3600, *et seq*., serve two primary functions. First, the rules require a regular, periodic examination of an electric utility's energy sales and demand forecasts as compared to an assessment of its existing resources to ensure that sufficient generation will be available to meet customer needs in the future. Second, the Commission's review and approval of an ERP ensures that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives.

11. As established in the ERP Rules, for decades Colorado electric utilities have used competitive bidding to procure additional resources to meet identified future resource needs. An ERP thus describes in detail how the utility will evaluate the bids and proposals submitted in response to Requests for Proposals (RFPs), including the inputs and assumptions to its bid evaluation models (*e.g.*, natural gas prices, the social costs of emissions, discount rates, etc.), and how it will apply resource selection criteria.

12. The ERP process includes two phases. In Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources.[6] In Phase II, the Commission issues a final decision regarding the utility's preferred cost-effective plan for pursuing the acquisition of particular resources.

[6] Rule 4 CCR 723-3-3617(c) describes the contents of the Commission's Phase I decision in more detail.

13. Phase II begins after the Commission issues its Phase I decision. Public Service issues its RFPs, receives competitive bids and utility-owned proposals, and files a report no later than 120 days after the bids are received in accordance with Rule 4 CCR 723-3-3613(d) (120-Day Report). The 120-Day Report presents an evaluation of all proposed resources, based on the criteria established in the Phase I decision (*e.g.*, the base modeling inputs and assumptions to be used in developing optimized resource portfolios and the sensitivities that "re-price" optimized portfolios using alternative values for selected inputs and assumptions).

14. At the end of Phase II, the Commission issues a final decision that approves, conditions, modifies, or rejects the utility's preferred cost-effective resource plan. Rule 3613(h) describes the contents of a Phase II decision as follows:

> Within 90 days after the receipt of the utility's 120-day report under paragraph 3613(d), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan. The utility shall pursue the final cost-effective resource plan either with a due diligence review and contract negotiations, or with applications for CPCNs (other than those CPCNs provided in paragraph 3611(e)), as necessary. In rendering the decision on the final cost-effective resource plan, the Commission shall weigh the public interest benefits of competitively bid resources provided by other utilities and non-utilities as well as the public interest benefits of resources owned by the utility as rate base investments. In accordance with §§ 40-2-123, 40-2-124, 40-2-129, and 40-3.2-104, C.R.S, the Commission shall also consider renewable energy resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that affect employment and the long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

15. Upon the conclusion of Phase II, and consistent with Rule 3613(h), upon the issuance of this Phase II Decision, Public Service will continue its due diligence and contract negotiations, as appropriate, and file applications for CPCNs in accordance with § 40-5-101, C.R.S., for each of the Company-owned projects arising from approval of the modified CEP.

These projects will be entitled to a presumption of prudence per Rule 3617(d), supported primarily through the determinations of need in Phase I and Phase II, the use of competitive bidding, and the implementation of bid evaluation and selection pursuant to our Phase I decision. Given the magnitude of this ERP Proceeding and the complexity associated with the CEP considerations set forth below, the Commission waives the 90-day deadline to issue a Phase II decision as contemplated by Rule 3613(h).

**2. Clean Energy Plans Pursuant to SB 19-236**

16. While longstanding statutes, the Commission's rules, and competitive bidding processes are foundational to the Colorado's utility resource planning process, recent legislative changes, including Senate Bill (SB) 19-236 further overlay CEP considerations on Public Service's current ERP.

17. SB 19-236 enacts § 40-2-125.5(1) that declares the statewide importance of promoting cost-effective clean energy and new technologies and reduction of carbon dioxide emissions from the Colorado electric generating system and includes that "[a] bold clean energy policy will support this progress and allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost." Specifically, § 40-2-125.5(3) requires that, in addition to the other requirements of the section, Public Service shall meet the following clean energy targets:

> (I) By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels; and
>
> (II) For the years 2050 and thereafter, or sooner if practicable, the qualifying retail utility shall seek to achieve the goal of providing its customers with energy generation from one-hundred-percent clean energy resources so long as doing so is technically and economically feasible, in the public interest and consistent with the requirements of this section.

18. The statute further requires that the first ERP following January 1, 2020, must include a CEP that "will achieve the clean energy target set forth in subsection (3)(a)(I)" and will "make progress toward the [100 percent] clean energy goal set forth in subsection (3)(a)(II)."[7] Subsection 4 further specifies what a CEP must include (*e.g.*, a plan of actions and investments projected to achieve compliance with the clean energy targets set forth in subsection (3)(a)(I) and (3)(a)(II), the projected costs of the CEP's implementation, and workforce transition and community assistance plans).

19. Subsection 4(d) includes that the Commission "shall approve the [CEP] if the commission finds it to be in the public interest and consistent with the [80 percent target], and the commission may modify the plan if the modification is necessary to ensure the plan is in the public interest." In evaluating whether a CEP submitted is in the public interest, the Commission is directed to consider the following factors, "among other relevant factors as defined by the commission":

> (I) Reduction in carbon dioxide and other emissions that will be achieved through the clean energy plan and the environmental and health benefits of those reductions;
>
> (II) The feasibility of the [CEP's] impact on the reliability and resilience of the electric system. The commission shall not approve a plan that does not protect system reliability.
>
> (III) Whether the [CEP] will result in a reasonable cost to customers, as evaluated on a net present value basis.[8]

20. If the Commission approves a CEP that achieves an emission reduction of at least 75 percent from 2005 levels, then the relevant utility is provided with a "safe harbor" from any

[7] § 40-2-125.5(4)(a).
[8] § 40-2-125.5(4)(d)(III).

additional emission reduction regulations that the Air Quality Control Commission (AQCC) might develop for the power sector through 2030.[9]

21. As a general matter, the Colorado Department of Public Health and Environment (CDPHE) is tasked with calculating whether a proposed CEP will meet these clean energy targets. In particular, the division of administration in the CDPHE must describe the methods of measuring CO2 emissions and verify the projected CO2 emission reductions of the CEP.[10] The statute goes on to state that the division of administration, in consultation with the AQCC, must determine whether the CEP will meet the 2030 clean energy targets, and will report to the Commission the division's calculation of CO2 emission reductions attributable to any approved CEP.[11]

22. SB 19-236 also sets forth accounting requirements to track the costs of the CEP. For instance, § 40-2-125.5(4)(a)(III) states the utility must "clearly distinguish" between the set of resources necessary to meet customer demands in the resource acquisition period (RAP) and the additional CEP activities—such as the retirement of existing generating facilities—that may be undertaken to meet the clean energy target of 80 percent emission reduction by 2030. Moreover, the CEP must set forth the projected cost of its implementation and anticipated reductions in carbon dioxide and other emissions.[12] Likewise, the CEP must list the "actions and investments" necessary to meet the clean energy target and describe the effect of such actions and investments on the safety, reliability, renewable energy integration, and resiliency of the electric system.[13]

23. The statute goes on to direct the utility to collect revenues for the additional CEP activities through a CEPR assessed on a percentage basis on all retail customer bills.[14] This CEPR

[9] § 25-7-105(1)(e)(VIII)(C), C.R.S.
[10] § 40-2-125.5(4)(b).
[11] § 40-2-125.5(4)(c)(1).
[12] § 40-2-125.5(4)(a)(VI)
[13] § 40-2-125.5(4)(a)(IV)—(V).
[14] § 40-2-125.5(5)(a)(II)

is limited to a maximum electric retail rate impact of 1.5 percent of the total annual electric bill for each customer for implementation of the approved additional clean energy plan activities and "may be established as early as the year following approval of a clean energy plan by the commission."[15]

24. SB 19-236 requires that the ERP containing the CEP use a RAP extending through 2030. If the CEP calls for the accelerated retirement of any generating facilities, the CEP must include a workforce transition plan for impacted utility workers. Similarly, the CEP must include a plan to pay community assistance to any local government or school district whose voters previously approved projects, the costs of which are expected to be paid for from property taxes that the accelerated retirement directly impacts.[16]

25. While the statute requires the utility to use a competitive bidding process to procure any energy resources to fill the cumulative resource need derived from the ERP and CEP, the Commission shall also allow the utility to own a target of 50 percent of the energy and capacity developed or acquired to meet the resource need "if the commission finds the cost of utility or affiliate ownership of the generation assets comes at a reasonable cost and rate impact."[17]

26. As discussed in our Phase I Decision, several of the statutory findings required for an approved CEP could not be made in the Phase I Decision but must wait until Phase II. For instance, the actions and investments required to fill the additional resource need for the CEP, the projected cost to implement the CEP, and the cost and rate impact of the 50 percent utility ownership target could not be known until after the 120-Day Report. The Phase I Decision permitted Public Service to issue the RFP and proceed to Phase II and established the framework in which bids will be evaluated and selected, setting important Phase II assumptions regarding the

[15] § 40-2-125.5(5)(a)(I).
[16] § 40-2-125.5(4)(a)(VII).
[17] § 40-2-125.5(5)(b).

treatment of the Company's remaining coal-fired power plants, and ensuring that the 120-Day Report contains the information required to make the statutory findings necessary to reach an approved CEP.

27. The Commission did not anticipate, and no party requested, a fully litigated hearing in Phase II.[18] Rather, through its usual Phase II process, the Commission can address the necessary statutory findings in this Phase II Decision (*e.g.*, upon consideration of the 120-Day Report, the parties' comments to the 120-Day Report, and the IE Report). As the parties assert in their Joint Brief Addressing Phase II Topics, (filed on August 2, 2021) SB 19-236 might change the objectives of the ERP process, but it does not direct any changes to the process itself.[19]

**3. Procedural Background**

28. A complete procedural history through Phase I of this Proceeding is provided in the Phase I Decision.

29. The parties in this Proceeding consist of the following: Public Service; Staff of the Colorado Public Utilities Commission (Staff); the Office of Utility Consumer Advocate (UCA); the Colorado Energy Office (CEO); the City of Boulder (Boulder); the Colorado Energy Consumers (CEC); Climax Molybdenum Company (Climax); Colorado Independent Energy Association (CIEA); Interwest Energy Alliance (Interwest); Colorado Solar and Storage Association and Solar Energy Industries Association (jointly COSSA/SEIA); the International Brotherhood of Electrical Workers, Local No. 111 (Local 111); Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly,

[18] This is consistent with the position of the parties. (Joint Brief Addressing Phase II Topics, p. 8 (arguing that the statutory findings required to approve a CEP do not necessitate a Phase II hearing)).

[19] Joint Brief Addressing Phase II Topics, p. 13.

RMELC and CBCTC);[20] Holy Cross Electric Association, Inc. (Holy Cross); CORE Electric Cooperative (CORE); Western Resource Advocates (WRA); Vote Solar; Walmart Inc. (Walmart); Colorado Renewable Energy Society (CRES); Natural Resources Defense Council and Sierra Club (collectively, the Conservation Coalition); the City and County of Denver (Denver); the Board of County Commissioners of Pueblo County (Pueblo County); the City of Pueblo and Board of Water Works of Pueblo (jointly Pueblo City and Water); Onward Energy Management (Onward); and the Colorado Oil and Gas Association (COGA). The Commission also granted Black Hills Colorado Electric, LLC (Black Hills) leave to participate as an *amicus curiae* in this Proceeding.[21]

30. In addition, in Decision No. C21-0343-I,[22] the Commission granted the Unopposed Motion for Limited Participation that CDPHE filed on April 29, 2021. As such, CDPHE is participating in this Proceeding as a neutral verifier.

31. In response to Decision No. C21-0404-I,[23] in which the Commission solicited briefs from the parties regarding Phase II procedures, on August 2, 2021, Public Service, Staff, UCA, CEO, CIEA, COSSA/SEIA, RMELC and CBCTC, Local 111, Conservation Coalition, Interwest, Onward, Pueblo County, Pueblo City and Water, Walmart, and WRA jointly filed a brief arguing that no Phase II hearing is required. Vote Solar was the only party to file a separate Phase II brief, in which it states that it "does not believe Senate Bill 19-236 requires a Phase II hearing" but argues that "additional evidentiary hearing process may nonetheless be necessary in Phase II if Public Service Company of Colorado proposes any portfolios in its 120-Day Report that include gas plants located in, or near, any disproportionately impacted communities."[24]

[20] Local 111, RMELC, and CBCTC collectively refer to themselves as the Labor Interests.
[21] The Commission denied the Motions to Intervene filed by Ms. Leslie Glustrom and the Coalition of Ratepayers. (Decision No. C21-0315-I, pp. 16-22.)
[22] Issued June 9, 2021.
[23] Issued June 23, 2021.
[24] Vote Solar's Phase II Brief, p. 1.

32. On September 30, 2021, the Office of Just Transition (OJT) filed a motion to intervene out of time, or in the alternative, to participate as *amicus curiae*. On October 25, 2021, the Commission granted OJT's motion to intervene out of time, allowing OJT to participate as a party in this Proceeding.[25]

33. On August 3, 2022, the Commission issued the Phase I Decision addressing Public Service's ERP and CEP and approving, in part, the Updated Non-unanimous Partial Settlement Agreement (Phase I Settlement) filed on April 26, 2022.[26] Among other things, the Phase I Decision directed Public Service to issue RFPs for an all-source, competitive bidding process to meet its resource need.

34. On September 21, 2022, the Commission issued Decision No. C22-0559 addressing applications for rehearing, reargument, or reconsideration of the Phase I Decision.

35. On December 1, 2022, Public Service issued its 2022 All-Source RFPs.

36. On March 31, 2023, Public Service filed its "30-Day Report" describing bids received in response to its competitive bid solicitation.

37. On March 31, 2023, Public Service filed an unopposed motion to, among other things, extend by 50 days the time to file the 120-Day Report. By Decision No. C23-0246-I,[27] the Commission granted the Company's motion and extended the deadline for the 120-Day Report as well as all associated deadlines.

[25] Decision No. C21-0666-I, issued October 20, 2021.

[26] The Phase I Settlement was supported by the following parties: Public Service, Staff, UCA, CEO, RMELC and CBCTC, COSSA/SEIA, Pueblo County, Holy Cross, Pueblo City and Water, Walmart, Boulder, Denver, COGA, Local 111, the OJT, CIEA, Onward, Interwest, Conservation Coalition, and WRA.

[27] Issued on April 13, 2023.

38. On July 27, 2023, Public Service filed the Motion for Second Extension requesting an additional 24-day extension of time within which to file the 120-Day Report. By Decision No. C23-0522-I,[28] the Commission granted the Motion for Second Extension.

39. On September 5, 2023, Public Service together with the Independent Evaluator (IE) and Staff filed a Motion that requested a third extension of time for the Phase II deadlines. On September 5, 2023, various parties representing the interests of independent power producers (IPPs) filed a Response to the Joint Motion for Third Extension (Joint IPP Interests Response). The Joint IPP Interests Response was specifically filed by COSSA/SEIA, CIEA, and Interwest. These parties argued that the IPP projects will be prejudiced by the additional requested delay, which could postpone final decisions in this matter through March of 2023 to consider requests for rehearing, reargument, and reconsideration. By Decision No. C23-0594-I[29] and Decision No. C23-0647-I,[30] the Commission granted, in part, and denied, in part, the requested Phase II extensions. While the Commission recognized the significant complexity of this Phase II process relative to past ERPs, it agreed with other parties regarding the urgency of issuing a Phase II decision.

40. Ultimately, the Company filed the 120-Day Report on September 18, 2023, approximately 80 days after the Company was initially scheduled to file the 120-Day Report.[31] Public Service would subsequently file corrections to the 120-Day Report on October 18, 2023.

[28] Issued on August 8, 2023.
[29] Issued September 7, 2023.
[30] Issued September 27, 2023.
[31] The original deadline for the 120-Day Report was June 29, 2023. (Decision No. C23-0246-I, ¶ 4).

41. On October 5, 2023, the Commission issued Decision No. C23-0672-I, that required the Company, and invited other parties, to submit comments outlining a potential risk sharing mechanism for Company-owned generation.

42. On October 18, 2023, the Air Pollution Control Division of the CDPHE filed the Phase II Clean Energy Plan Verification Report.

43. On October 20, 2023, in response to Decision No. C23-0672-I, Public Service submitted a proposal for risk-sharing mechanisms regarding Company-owned generation resources. Staff similarly filed a proposal on October 20, 2023, which UCA and CEC joined.

44. On October 21, 2023, the IE filed its report (the IE Report).

45. On November 8, 2023, intervenor comments on the 120-Day Report were filed.

46. On November 20, 2023, Public Service filed its Response Comments to the 120-Day Report.

47. On December 6 and 13, 2023, the Commission commenced deliberations. On December 13, 2023, the Commission also issued Decision No. C23-0841-I, directing Public Service to set forth certain information related to the cost-to-construct performance incentive mechanism (PIM) and the operational PIM. In addition, we instructed the Company to consider and potentially refile the Highly Confidential Exhibit 1 to the Response to Decision No. C23-0672-I.

48. On December 19, 2023, Public Service filed its Response to Decision No. C23-0841-I, providing the specific information requested, and a corresponding narrative on the identified highly confidential document.

49. The Commission resumed deliberations on December 20, 2023, and concluded deliberations that same day.

50. In addition to the public comment hearings and written comments provided in Phase I, throughout Phase II of this Proceeding, the Commission received numerous written public comments that the Commission reviewed and retains in the administrative record.

### C. Phase I Decision and Public Service CEP

51. In the Phase I Decision, the Commission set the framework in which Public Service may proceed to issue RFPs for an all-source, competitive bidding process to meet its resource need and advance its CEP toward final consideration and approval. The Commission's rulings on topics such as the Company's coal action plan, workforce transition and community assistance, best value employment metrics (BVEMs), and the CEPR paved the way for the development of a CEP in Phase II that complies with the requirements of SB 19-236 and advances the establishment of a bold clean energy policy for Colorado.

52. The following list summarizes the primary rulings the Commission made in its Phase I Decision that relate to the Company's CEP and the requirements of SB 19-236:

a) Consistent with the Phase I Settlement, the resource acquisition period (RAP) for the Company's ERP/CEP extends through 2030 per § 40-2-125.5(4)(a)(I).
b) Subject to certain exceptions, starting in 2024, the Company must retire all RECs in the year generated, per § 40-2-125.5(3)(a)(III).
c) In the 120-Day Report, the Company will clearly distinguish between the set of resources necessary to meet customer demands in the resource acquisition period and the additional clean energy plan activities that may be undertaken to meet the clean energy target in § 40-2-125.5(3)(a)(I), per § 40-2-125.5(4)(a)(III).
d) In the 120-Day Report, the Company will set forth the actions and investments required to meet the clean energy target of § 40-2-125.5(3)(a)(I).
e) The Company will set forth a proposal for the CEPR as part of the 120-Day Report that enables us to consider the appropriate timing for Public Service to initiate the CEPR via an advice letter filing.
f) The suite of portfolios the Company will present in the 120-Day Report will allow the Commission to evaluate whether the proposed level of utility ownership comes at a reasonable cost and rate impact per § 40-2-125.5(5)(b).

g) Consistent with the Phase I Settlement, the 120-Day Report will include the information necessary for the Commission to consider BVEM in conjunction with our other Phase II decisions.

h) The Company will include the projected costs of both workforce transition plans and community assistance plans in the Phase II modeling. The estimated cost of the community assistance aspect will be equal to projected lost property tax revenues for six years following retirement (or conversion) for Hayden 1 and Hayden 2, and Pawnee (the Brush Coal plant), respectively, and ten years for Pueblo Unit 3, and will be offset by any new investment in the respective community.[32]

i) Public Service will file post-Phase II updated Just Transition Plans (JTPs) for the Hayden coal plants, the Brush Coal Plant, and Pueblo Unit 3.[33] Regarding the Pueblo Unit 3 in particular, no later than June 1, 2024, Public Service will file a JTP that includes a standalone competitive solicitation. To the extent not otherwise addressed in the Phase I Settlement, this 2024 Just Transition Solicitation (the 2024 JTS) shall be treated as an interim ERP under Rule 3603(a). While the focus of the 2024 JTS is the replacement of Unit 3 and the Pueblo community, the 2024 JTS is not geographically limited to the Pueblo area nor is the resource need limited to replacing Unit 3.[34]

j) The Phase II modeling will allow the Commission to evaluate both the social cost of carbon (SCC) and the social cost of methane (SCM), consistent with the spirit of § 40-3.2-106.

53. In addition, the Phase I Decision ruled on such things as the provisions in the Company's model PPA, the inputs and assumptions to be used in the Phase II modeling, and the portfolios and sensitivities that the Company will present in the 120-Day Report.

## D. Phase II Filings

### 1. 120-Day Report

54. The 120-Day Report summarizes the results of the Public Service's Phase II modeling and puts forth the Company's Preferred Portfolio for Commission approval. Under the Preferred Portfolio, the Company would move forward with developing numerous generation resources and associated transmission infrastructure. While the relevant details of the 120-Day

[32] Phase I Settlement, pp. 18-19.
[33] Phase I Settlement, p. 19.
[34] Phase I Decision, pp. 40, 42; Phase I Settlement, pp. 27-31.

Report and the subsequent Updated Preferred Plan (UPP)will be discussed below, we highlight here some of the major components.

55. Public Service's Preferred Portfolio contains about half as much gas-fired generation resources as what the Phase I modeling predicted (628 MW versus 1,176 MW).[35] Conversely, the Preferred Portfolio adds almost twice as much renewable generation and six times as much storage as was anticipated in Phase I.[36] As to the storage specifically, Public Service states that the Preferred Portfolio takes advantage of the IRA tax benefits for storage, and uses storage to "effectively utilize otherwise curtailed renewable energy, provide critical ancillary services, and meet peak demand in the evenings when solar generation declines."[37]

56. Regarding emissions reductions, Public Service estimates that the Preferred Portfolio will achieve 87.4 percent reduction in CO2 emissions by 2030—far exceeding the 80 percent clean air target.[38] Public Service acknowledges, however, that "in addition to all of the normal variance in forecasting, the modeling process itself leads to structural optimism in emissions reduction potential" and that "real time operations will likely have less optimistic results than those predicted by the models."[39] The Company states that it "believes we would likely achieve an 80%-85% reduction."[40]

57. The emissions reductions are due largely to the Coal Action Plan and the renewable resources the Preferred Portfolio adds as replacement and new utility resources. Indeed, Public Service states that the Preferred Portfolio is "the largest portfolio ever advanced through the ERP

[35] 120-Day Report, p. 36.
[36] 120-Day Report, p. 36.
[37] 120-Day Report, p. 36.
[38] 120-Day Report, p. 38.
[39] 120-Day Report, p. 23.
[40] 120-Day Report, p. 24.

process."[41] Public Service estimates that through 2055 the Preferred Portfolio has a net present value (NPV) of approximately $44.2 billion. Included in this total price is an estimated $2.82 billion in transmission investments. By far the most significant portion of the total transmission investment is an estimated $2.2 billion needed for Denver Metro Transmission Network Upgrades.[42]

58. The Preferred Portfolio includes higher levels of Company-owned resources compared to past ERPs. Out of the 7,192 MW of nameplate capacity additions that would be acquired under the Preferred Portfolio, Public Service would own 66.6 percent of the capacity and 69.7 percent of the energy. The Company argues that the higher ownership percentage is a direct result of the more equitable tax credit policy for clean energy resulting from the historic IRA.[43]

### 2. CDPHE Verification

59. On October 18, 2023, CDPHE filed the Phase II CEP Verification Report. In its Verification Report, CDPHE opines that the GHG emissions reduction calculations for each portfolio submitted in this Phase II of Proceeding No. 21A-0141E are expected to be 80 percent or more below 2005 baseline levels. CDPHE further states that the portfolios "would be expected to achieve the minimum percent reduction levels required by the statutes for the CEP and Safe Harbor."[44]

60. In its Phase II CEP Verification Report, CDPHE lists the expected 2030 emissions reductions for each of the submitted portfolios. Of note, the expected emissions reductions for the Preferred Portfolio is 87 percent.[45]

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[41] 120-Day Report, p. 22.
[42] 120-Day Report, p. 130.
[43] 120-Day Report, p. 40-41.
[44] CDPHE Phase II CEP Verification Report, p. 6.
[45] CDPHE Phase II CEP Verification, pp. 4-6.

### 3. IE Report

61. On October 21, 2023, the IE filed its Report in this Proceeding. In its Report, the IE attests that the Phase II process was conducted fairly and without bias. The IE states: "The IE can attest to the results of the evaluation and fidelity to the protocols and that the Phase I assumptions were used in evaluation. The IE also was unable to identify any bias towards or against any technology or respondent, including the options presented for the [Public Service] self-owned assets."[46]

62. That said, the IE also raised several recommendations for future ERP proceedings that the IE asserts will allow the process to better accommodate the large number of bids and increasing reliance on renewable resources. For example, the IE states that "inadequate time was allotted for the transmission analysis" and suggests changes going forward that allow for a better understanding of the transmission requirements associated with the proposed generation projects.[47]

### 4. Intervenor Comments

63. Numerous intervenors submitted comments on the 120-Day Report, including Staff, CEO, the UCA, CEC, CIEA, COSSA/SEIA, Interwest, WRA, the Conservation Coalition, Boulder, CRES, the OJT, and the Labor Interests.

64. Several parties, such as CEO, WRA, CRES, and Conservation Coalition, cite concerns with the Phase II modeling process and recommend selecting an alternative portfolio with fewer gas resources or simply removing some or all of the gas resources from the Preferred Portfolio.[48] Conversely, UCA argues that the Phase II modeling shows that eliminating gas-fired

[46] IE Report, p. 35.
[47] *See* IE Report, p. 37.
[48] CEO's Comments, pp. 13-14; WRA's Comments, pp. 15-17; CRES's Comments, p. 2; Conservation Coalition's Comments, pp. 12-13.

capacity is extremely expensive.[49] CEC similarly argues that the Commission should approve a less-costly portfolio that meets but does not greatly exceed the required emissions reductions.[50]

65. Some parties, including Boulder and UCA, suggest that the existing resources in the Preferred Portfolio could be replaced with other resources that they perceive to be lower-priced.[51]

66. Other parties representing IPP interests, like CIEA, argue that the Commission should choose an alternative portfolio that better balances how many resources will be owned by Public Service versus IPPs.[52] Conversely, the Labor Interests argue that there is a positive relationship between portfolios with high BVEM and portfolios with high Company-ownership numbers.[53]

67. At a high level, the parties have mixed opinions regarding the transmission investments presented in the 120-Day Report—some raise serious concerns while others argue the Commission should approve and expedite the transmission. Likewise, several parties raise cost and emissions concerns about the Hayden Biomass project, while other parties argue that the project should be included in any approved portfolio.

68. Out of the intervenors that filed comments, it appears that the Labor Interests, COSSA/SEIA, the OJT, and Pueblo County, do not oppose adoption of the Preferred Portfolio as presented.[54]

[49] UCA's Comments, p. 17.
[50] CEC's Comments, pp. 12-13.
[51] *See* UCA's Comments, pp. 20-24; Boulder's Comments, pp. 14-15.
[52] CIEA's Comments, pp. 12-15.
[53] Labor Interests' Comments, pp. 2.
[54] *See, e.g.*, Labor Interests' Comments, pp. 2; COSSA/SEIA's Comments, pp. 1-2.

69. For its part, Staff raises concerns that Public Service's Preferred Portfolio is too aggressive, too costly, and not well supported. Staff states that the Preferred Portfolio contains unexpectedly large generation and transmission investments and high levels of expected curtailments that together could lead to potentially large rate impacts for customers.[55] Staff encourages the Commission to consider selecting one of five smaller portfolios that would reduce expected curtailments, enable the Commission to defer some of the proposed projects, and to further analyze alternatives for the proposed transmission investments.

#### 5. Comments from the Northern Cheyenne Nation

70. At the CWM on October 25, 2023, William Walksalong presented comments on behalf of the Northern Cheyenne Nation regarding the potential impacts to the Sand Creek Massacre National Historic Site. As described more below, tribal leaders urged the Commission to protect the Sand Creek Massacre National Historic Site as sacred grounds and its view shed from the encroachment of energy development.

#### 6. Public Comments

71. After Public Service filed the 120-Day Report, the Commission received numerous public comments. Many of these public comments argue against the Preferred Portfolio's inclusion of three new-build gas facilities that Public Service would own. At a high level, these comments urge the Commission to reject the new natural gas plants, citing concerns regarding stranded costs, climate change, and air pollution. The Commission also received more substantive public comments from Leslie Glustrom, Advanced Energy United, Sustainable Resilient Longmont, and 350 Colorado that similarly argue for modifications to the Preferred Portfolio, including not approving the proposed gas facilities in the Preferred Portfolio.

[55] Staff's Comments, pp. 5-7.

72. In addition, the Commission received several comments from organizations and local governments like Upstate Colorado, Alamosa County, the City of Alamosa, Kiowa County, Prowers County, Baca County, and Pueblo County that support the Preferred Portfolio on the basis of emissions reductions and economic development. Of these supportive comments, several public comments specifically support the inclusion of the Hayden Biomass facility in the Preferred Portfolio, arguing that it will provide important economic benefits to Moffat and Routt Counties, which will be impacted by the closure of coal-fired power plants. Northwest Colorado Development Council, Routt County, Colorado State Senator Dylan Roberts, and the Town Council and Mayor of Hayden are some of the entities that submitted these types of comments specifically addressing the Hayden Biomass facility.

73. Since the Commission had its initial Phase II deliberations on December 6, 2023, we have continued to receive and review numerous public comments. At a high level, the majority of these most recent public comments urge the Commission to select a resource portfolio with fewer or no gas resources on the basis of climate change, air pollution, price volatility for natural gas, or concerns that the resources will become stranded. Several of the public commenters argue that the Alternative Portfolio is more expensive on a dollar per MW basis than the Company's UPP.

### 7. Public Service's Response Comments and the UPP

74. In its Response Comments, Public Service responds to criticisms and concerns raised by intervenors and public commentors and presents an UPP that modifies a few of the proposed generation projects. Aside from the modifications to a few of the generation projects, however, the Company largely maintains its initial position in the 120-Day Report.

75. For example, in response to arguments that the Commission should reduce or eliminate the amount of gas resources included in the portfolio, Public Service asserts that—due to reliability concerns—the Company "cannot become comfortable with any level of reduction in dispatchable resources."[56] Public Service argues that adjusting the portfolio by eliminating gas units or using questionable short-term power purchase agreement (PPA) extensions makes the portfolio less reliable and the Company "cannot compromise on reliability."[57]

76. As for arguments that the UPP has too many utility-owned resources or is too large, the Company argues that all of the selected clean energy projects are either build-own-transfer, PPA, or were purchased from IPPs by the Company earlier in the commercial lifecycle. Public Service agrees that the UPP is large but asserts that the size of the portfolio is ultimately driven by economics and state energy policy goals.[58]

77. Turning to the concerns raised about the approximately $2.8 billion in transmission investments, Public Service states that the ultimate decision before the Commission is approval of a generation portfolio and that "approval of a resource portfolio does not constitute a final approval of the transmission projects presented in the 120-Day Report."[59] Public Service maintains, however, that to achieve the State's emissions reduction goals, the Company must begin moving forward with the transmission investments needed to support the CEP.[60]

78. As for the proposed resource modifications under the UPP, in response to concerns that Bid 1029 could impact the Sand Creek Massacre National Historic Site due to its proximity, in the UPP, Public Service recommends that the Commission approve a specific backup bid for

[56] Public Service's Response Comments, p. 29.
[57] Public Service's Response Comments, pp. 27-29.
[58] Public Service's Response Comments, pp. 33-34.
[59] Public Service's Response Comments, p. 66.
[60] Public Service's Response Comments, p. 65.

Bid 1029 while still allowing Bid 1029 to move forward. Similarly, the Company proposes that the Commission conditionally approve the Hayden Biomass project but further analyze the costs, emissions reductions, workforce and community benefits, tax benefits, and viable alternatives in a follow-on CPCN proceeding.[61]

79. The Company proposes a few other changes to the resources in the UPP, but the suggested changes result from problems with the original resources as opposed to intervenor concerns.[62]

80. As compared to the Preferred Portfolio, the UPP adds 329 MW of nameplate capacity. This increase is comprised of an additional 101 MW of solar resources and an additional 228 MW of additional wind resources. The UPP is also $288 million more expensive on a present value revenue require (PVRR) basis.[63] Regarding the price increase, Public Service asserts that the $288 million increase is caused by unavoidable changes to bids that appear in virtually all portfolios. Thus, the Company asserts that all of the other portfolios would increase by the same amount, meaning there is little to no impact on the differences between plans.[64] The percentage of resources that the Company would own decreases slightly in the UPP from 66.6 percent of capacity to 62.7 percent.[65]

### E. Modification of the CEP's Resource Portfolio

81. As described above, the statute prescribes when the Commission must approve a CEP and when the Commission may modify the CEP. Specifically, the Commission may modify the plan if the modification is necessary to ensure the plan is in the public interest. In evaluating

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[61] Public Service's Response Comments, pp. 19-20.
[62] Public Service's Response Comments, pp. 18-24.
[63] Public Service's Response Comments, p. 9.
[64] Public Service's Response Comments, p. 9.
[65] Public Service's Response Comments, p. 9.

whether a CEP submitted to the Commission is in the public interest, the Commission shall consider (1) emissions reductions, (2) the CEP's impact on reliability and resilience of the electric system,[66] and (3) the cost of the CEP on a NPV basis. The statute also permits the Commission to consider "other relevant factors."

82. A CEP includes "clean energy plan activities that may be undertaken to meet the clean energy target… which may create an additional resource need for the [CEP]."[67] Public Service's CEP is thus comprised of several components, including the Coal Action Plan, the workforce transition and community assistance plans,[68] and the "investments required to fill the additional resource need,"[69] (*i.e.*, the portfolio of resources procured through the competitive solicitation). In this Proceeding, significant clean energy plan activities involve the conversion of the Brush plant from coal to gas and the lower capacity values of Pueblo Unit 3.[70] The UPP represents a portion of Public Service's CEP as proposed by the Company.

83. Given that the Company's preferred resource portfolio comprises a portion of the total CEP, the selection of an alternative resource portfolio does not replace the overall CEP. Because the Commission maintains the other important elements of the CEP—like the Coal Action Plan—the selection of an alternative portfolio is a modification to the overall CEP.

84. While the Commission recognizes that Company proposals in Phase I and II in this Proceeding have made progress towards Colorado's energy transition, there are significant

[66] The statute makes clear that the Commission "shall not approve a plan that does not protect system reliability." (§ 40-2-125.5(4)(d)(III), C.R.S.)
[67] § 40-2-125.5(4)(a)(III), C.R.S.
[68] § 40-2-125.5(4)(a)(VII), C.R.S.
[69] § 40-2-125.5(4)(a)(IV), C.R.S.
[70] Although the Coal Action Plan includes the early retirement of the Hayden and Craig coal plants, the coal actions are not technically part of the CEP because they are also included in the reference ERP portfolio.

concerns raised by parties and public commenters regarding the UPP.[71] For instance, Staff argues that given the large price tag of the Preferred Portfolio as well as the concerns Staff has about the Phase II modeling process, the Commission should reduce the size of the resource portfolio or delay decisions until further analysis and support can be provided.[72] Regarding its modeling concerns, Staff notes that Public Service's decision to increase the generic price of most renewables for years 2029 and 2030 might be causing the model to over-value acquisitions in the near-term.[73] Similarly, the reliability rubric the Company implemented in Phase II arguably prohibited the model from "backsliding" or removing resources after dispatchable resources were added. Staff states that the reliability rubric "introduced constraints into the capacity expansion step that fundamentally render the process suboptimal as it is no longer able to truly optimize the portfolio."[74] Staff goes on to suggest that the reliability rubric's constraints made the Commission-ordered demand response sensitivity ineffective.[75]

85. In addition, Staff notes that the Preferred Portfolio likely fails to account for high levels of curtailment and the resulting increase in costs and emissions. Staff argues that the model likely fails to capture significant levels of curtailments for several reasons, including the model's limitations regarding simplified commitment logic and the inability to capture curtailments from perturbations in the system as well as the timing mismatch between when generation will come online and when the transmission will be ready to serve the new generation. Staff ultimately concludes that the "the level and costs of curtailments portrayed by the model cannot be trusted"

[71] Because Public Service presented the UPP after intervenors submitted their Comments on the 120-Day Report, intervenors address the Preferred Portfolio rather than the UPP. The differences between the UPP and the Preferred Portfolio, however, are largely immaterial as to the concerns that the intervenors raise.
[72] Staff's Comments, p. 6.
[73] Staff's Comments, p. 28.
[74] Staff's Comments, p. 30.
[75] Staff's Comments, pp. 34-35.

and that the Preferred Plan "may saddle customers with extra costs for renewable energy that does not reduce emissions because it is never delivered."[76] In contrast, Staff notes that other portfolios presented in the 120-Day Report achieve comparable levels of emission reductions with much lower levels of curtailments and higher levels of storage.[77]

86. UCA also criticizes the Phase II modeling process and is especially critical of the May Valley Longhorn Extension (MVLE) and the most expensive part of the Denver Metro Area transmission upgrades—the Harvest Mile Chambers-Sandown-Cherokee (HCSC) project. UCA recommends that the Commission reject the HCSC, the MVLE, and the wind projects that UCA argues necessitate the transmission projects.[78]

87. Other parties, such as Conservation Coalition and CRES argue that the Commission should not approve any of the gas resources in the Preferred Portfolio.[79] CEO similarly recommends the Commission not approve 200 MW of the 628 MW of gas included in the Preferred Portfolio. CEO argues that it is unclear whether an additional 200 MW of new gas generation will actually be necessary and recommends that the Commission address this proposed new gas in future ERPs, including the 2024 JTS and the 2026 ERP.[80] WRA suggests that the Commission select the lower dispatchable portfolio, which has 504 MW of new gas generation—124 MW less than the Preferred Portfolio.[81] WRA also suggests modifying the Preferred Portfolio by reducing reliance on new construction and instead utilizing available existing generation.[82]

[76] Staff's Comments, pp. 31-32, 34.
[77] Staff's Comments, p. 32.
[78] *See* UCA's Comments, pp. 29-30.
[79] Conservation Coalition's Comments, p. 10; CRES's Comments, p. 2. Relatedly, the Commission has received numerous public comments urging the Commission to select a resource portfolio with fewer or no gas resources on the basis of climate change, air pollution, price volatility, or concerns that the resources will become stranded.
[80] CEO's Comments, p. 14.
[81] WRA's Comments, pp. 15-16.
[82] WRA's Comments, pp. 16-17.

88. CIEA raises several concerns with the Phase II modeling, arguing that the Company used a heavy-handed approach to manipulate the model.[83] Many of CIEA's recommendations are aimed at the goal of achieving a higher proportion of PPA resources in the Company's resource mix—both in this Proceeding and in future ERPs. CIEA asserts there have been "huge project cost overruns at the [Company-owned] Cabin Creek, Comanche, and Pawnee stations" and that customers are seeing less value than anticipated from two Company-owned wind projects.[84] CIEA argues that given the high percentage of Company-owned projects in the Preferred Portfolio, Public Service might be biting off more than it can chew.[85] CIEA reasons that PPA resources can help insulate ratepayers from both capital cost overruns and performance issues with generators. Noting that all of the gas resources in the Preferred Portfolio would be owned by Public Service, CIEA recommends that the Commission select an alternative resource portfolio that replaces some of the Company-owned gas-fired projects with existing PPA gas resources.[86] CIEA argues that PPA resources "should be at least 50% of Public Service's resource mix to balance ratepayer and shareholder risks."[87]

89. CEC argues that there are too many red flags and unknowns for this Commission to approve the Preferred Portfolio as presented. CEC notes that Preferred Portfolio will far exceed the clean air targets established by SB 19-236 and argues that the Commission should not approve a plan that goes "above and beyond" statutory requirements to the detriment of customers, particularly given the current affordability concerns.[88] For instance, CEC notes that the Preferred

[83] CIEA's Comments, pp. 26-28.
[84] CIEA's Comments, p. 13.
[85] CIEA's Comments, pp. 9-10.
[86] CIEA's Comments, pp. 16-18.
[87] CIEA's Comments, pp. 13-15.
[88] CEC's Comments, pp. 12-13.

Portfolio is approximately $600 million more expensive than the $0CO2 Least Cost Plan, and the $0CO2 Least Cost Plan still exceeds SB19-236 bold emission reduction targets.[89]

90. Given these concerns, and considering the record as a whole, we find that modification of the CEP in the selection of an alternative portfolio is necessary to ensure the plan is in public interest based on the three enumerated statutory factors as well as "other relevant factors" that the Commission defines.

91. As noted above, Staff recommends for several reasons that the Commission focus its consideration on five "portfolios of interest."[90] We agree with Staff and, consistent with the discussion below, determine that the Inverse 1324 ($0CO2) Plan best represents an "Alternative Portfolio" that incorporates the necessary modifications to Public Service's CEP to support the public interest findings required by SB 19-236.

92. Compared to the Preferred Portfolio set forth in the 120-Day Report, the Alternative Portfolio has 1,338 MW lower nameplate additions (7,192 MW – 5,854 MW). More specifically, the Alternative Portfolio has 19 MW fewer biomass, 41 MW more gas resources, 350 MW fewer solar resources, and 1,706 MW fewer wind resources. However, the Alternative Portfolio has 678 MW more storage resources.[91] The Alternative Portfolio also requires fewer transmission investments and is $194 million less expensive on a NPV basis. Regarding curtailments, the Phase II report suggests that in 2028 the Alternative Portfolio will result in 1,629 GWh of modelled curtailments, compared to 5,433 GWh of modelled curtailments in the Preferred Portfolio.[92] Moreover, the Company states in its Phase II Report that the modelled curtailment is the "best

[89] CEC's Comments, pp. 12-13.
[90] Staff's Comments, p. 11.
[91] *See* Staff's Comments, p. 49.
[92] *See* Staff's Comments, p. 49.

possible case scenario [rather] than a realistic expectation of [the curtailment level that]…would occur in real-time operations."[93] This uncertainty over actual curtailment levels further supports the more cautious approach taken with the Alternative Portfolio.

93. In addition, unlike three of the five portfolios of interest, the Alternative Portfolio was included in the 120-Day Report and thus was reviewed by the IE and CDPHE. As noted by Staff and confirmed by CDPHE, the emissions reductions resulting from the Alternative Portfolio exceed the 2030 greenhouse gas reduction targets. While the Alternative Portfolio has somewhat lower interim emissions reductions compared to the Preferred Portfolio, consistent with the Company's statements that the modeling does not capture curtailments resulting from transmission congestion and other perturbations in the system, Staff argues that it is unclear that the higher emissions reductions in the Preferred Portfolio "would bare out in reality" given the concerns regarding curtailments and the deliverability of the renewable energy.[94]

94. Moreover, the smaller size of the Alternative Portfolio addresses concerns raised by Staff and others that the Preferred Portfolio is too large due to factors such as the repricing of generic resources in the Phase II modeling and the no "backsliding" component of the Reliability Rubric modeling. Likewise, the smaller size ameliorates Staff's concerns about new generation coming online before the 2029/2030 in service date (ISD) for major transmission projects that Public Service indicates are necessary to take full advantage of the renewable resources.[95] Finally, the Alternative Portfolio reduces the Company's ownership percentage so that it is expected to be

[93] *See* 120-Day Report, at p. 95.
[94] Staff's Comments, p. 63.
[95] Staff's Comments, p. 61.

closer to the 50 percent IPP and 50 percent PPA statutory expectations.[96] Given the Company's significant upcoming investments in transmission through the Colorado Power Pathway and issues identified by intervenors of the Company's struggles to adhere to project budgets and timelines in different instances, a better balance between Company and IPP ownership presents an opportunity to decrease the risk of performance issues by a single entity impacting overall performance of the CEP.

95. Considering the statutory factors and additional public interest considerations raised in comments by parties and the public, based on this record and supported by party filings, we find that the Alternative Portfolio better aligns with Colorado's multi-faceted goals to achieve significant emission reductions and progress towards 100 percent emission reductions in the future, all while ensuring reliability and protecting affordability for ratepayers. Addressing specific factors below—and as supported by policy direction throughout our Phase II Decision that also includes PIMs and directives for the 2024 JTS—we find that modification of the CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest.

### 1. Emission Reductions

96. The statute requires the Commission to consider the emissions reductions associated with the CEP. Because the Alternative Portfolio is included in the 120-Day Report, CDPHE evaluated it along with all of the other Phase II portfolios in the Phase II Clean Energy Plan Verification Report. CDPHE opines that the emissions reduction calculations for each of the Phase II portfolios are expected to be 80 percent or more below 2005 baseline levels.

[96] To be clear, the Commission does not find that SB 19-236 in any way sets a floor or a ceiling for Company-ownership. The Commission does, however, find persuasive arguments from CIEA and others that more balanced levels of PPA and Company-owned resources help insulate ratepayers from potential cost overruns and performance issues.

Regarding the Alternative Portfolio in particular, CDPHE estimates that the expected 2030 emissions reductions will be 86 percent by 2030.[97] Thus, the Alternative Portfolio is expected to exceed the 80 percent emissions reductions set forth in the statute and makes progress towards achieving the goal of 100 percent clean energy resources by 2050.

97. As presented in the Phase II modeling, the UPP arguably achieves slightly greater emissions reductions, especially in the interim years prior to 2030. However, Public Service admits that these emissions reductions estimates are optimistic and that the model does not include curtailments caused by transmission congestion or perturbations in the system.[98] Thus, it is questionable how accurate these emissions reductions predictions are, especially in the interim years before Public Service has finished building the transmission upgrades the Company states are necessary to reliably deliver power.[99] In other words, these modeled interim emissions reductions are unlikely to materialize if Public Service cannot construct the majority of the associated transmission investments until 2030.[100] Moreover, it is these same transmission upgrades that resulted in the $2.2 billion "surprise" in Phase II, as discussed more below. We find it unsettling to rely on predictions that are speculative, at best, on transmission availability in the UPP that result in the seemingly higher emissions reductions. Given that the transmission modeling results changed dramatically between Phase I and II with costs escalating billions of dollars beyond the Company's initial estimates, we cannot depend on emission reduction predictions tied explicitly to those same transmission needs.

98. Throughout this Proceeding and in selecting the Alternative Portfolio, the Commission has considered the PVRR of both the social cost of carbon (SCC) and the social cost

[97] CDPHE Phase II CEP Verification, pp. 4-6.
[98] 120-Day Report, p. 95.
[99] 120-Day Report, pp. 130-133.
[100] *See* Staff's Comments, pp. 43-44 (citing Appendix Q to the 120-Day Report).

of methane (SCM), which also helps in our considerations on emission reductions. The Alternative Portfolio significantly reduces the SCC and SCM compared to Public Service's ERP or business-as-usual portfolio.[101] For the capacity expansion phase of the modeling, the Alternative Portfolio does not include the social cost of emissions.[102] Post-modeling, however, in the 120-Day Report the SCC and SCM associated with the Alternative Portfolio are both presented.[103] Moreover, the Coal Action Plan, which is critical to emissions reductions, is hardwired into the Alternative Portfolio. While there are other portfolios that have still greater reductions in SCC and SCM, notwithstanding the uncertainties around curtailment impacts to those figures, the Alternative Portfolio exceeds the 80 percent emissions reductions set forth in the statute while balancing other factors such as costs, reliability, and future optionality.

99. While the Alternative Portfolio—like other portfolios the Company claims protect reliability[104]—includes over 600 MW of gas resources, these gas resources do not impede Colorado's emissions reductions goals. Rather, the new gas resources are all equipped with both fast start and fast shutdown capability, which allows the units to sit idle most of the time while providing essential operating reserves and ancillary services.[105] The Commission reluctantly recognizes that there does not appear to be a path forward that excludes or significantly reduces the need for new gas resources, given the Company's repeated assertions that it cannot support any reduction in gas resources based on the Company's reliability analysis[106] and the lack of modeling demonstrating the contrary within the record.

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[101] 120-Day Report (Appendix S) Rev. 1, pp. 1, 26.

[102] 120-Day Report, p. 97.

[103] 120-Day Report (Appendix S) Rev. 1, p. 26.

[104] Public Service argues that the No New Gas and No Gas Portfolios are not reliable. The Lower Dispatchable portfolio includes somewhat fewer gas resources (504 MW), but the Company has raised reliability concerns with this portfolio as well. (Public Service's Response Comments, pp. 29-30).

[105] 120-Day Report, pp. 80-81, 126.

[106] Public Service Response Comments, p.29

100. Moreover, as discussed more below, rather than simply eliminating 200 MW of gas-fired resources as argued by some parties and sacrificing reliability, the Alternative Portfolio reduces the amount of Company-owned gas resources, increasing the Company's ability to fully transition away from carbon emitting resources as we approach 2050 and reducing risk of stranded assets to ratepayers. This reduction in Company ownership provides continued opportunities to further accelerate towards 100 percent renewable resources by not tying the Company – and Colorado – to the full amount of utility-owned gas-fired resources presented in the UPP.

101. Under SB 19-236, the CEP must achieve 80 percent emissions reductions by 2030 while working towards 100 percent clean energy by 2050, and the Commission must consider reliability and affordability when determining whether the CEP is in the public interest. The Alternative Portfolio with its 669 MW of gas resources provides this balanced, transitional plan that SB 19-236 contemplates. Even though the gas resources will be run infrequently with the vast majority of the energy coming from wind and solar resources, the units provide an important insurance policy during sustained periods of hot or cold weather – including in extreme circumstances given the realities of climate change.[107] Providing this backup option and permitting the integration of substantial additions of new clean energy resources allows Public Service to retire its remaining coal plants and several of its older gas units.[108]

102. In sum, when considering emission reductions, the Alternative Portfolio exceeds Colorado's ambitious emission reduction goals, sets the state towards a path for 100 percent renewable resources, all while continuing to avoid extreme costs and outages.

[107] 120-Day Report, pp. 22-23, 80-81.
[108] 120-Day Report, pp. 22-23, 80-81.

### 2. Reasonable Cost to Customers

103. The statute requires the Commission consider if the CEP will result in a reasonable cost to customers on an NPV basis. The NPV of the UPP is $44,479 million while the NPV of the Alternative Portfolio as presented is $43,997 million.[109] However, in its Response Comments, Public Service states that the $288 million NPV increase from the Preferred Portfolio to the UPP is a result of unavoidable changes that would appear in virtually all portfolios.[110] Assuming that the same incremental change appears in the Alternative Portfolio, the updated NPV of the Alternative Portfolio is $44,285 million ($43,997 + $288 = $44,285). Even using this updated NPV, the Alternative Portfolio is $194 million less expensive than the UPP ($44,479 - $44,285 = $194).

104. While the Alternative Portfolio is preferable to customers on an NPV basis as contemplated in SB 19-236, another relevant factor the Commission must consider is the cost to customers as experienced through increased rates. Intervenors such as Staff, UCA, and CEC have raised alarms regarding the Preferred Portfolio's impact on rates. For instance, Staff states that the rate increase attributable to the Preferred Portfolio for the single year from 2026 to 2027 is just over 10 percent.[111] As discussed more below, the rate analysis the Company provides in the 120-Day Report only includes the impact of the CEP and fails to include other planned investments such as $4.5 billion in projected distribution investments through 2028, an additional $800 million in generation projects outside of the CEP, as well as investments in wildfire mitigation, transportation electrification, distributed solar, and others.[112] Staff asserts that the impact of real time operations, construction schedules, system curtailments, and other factors will likely result in

[109] Public Service's Response Comments, p. 9; 120-Day Report (Appendix S) Rev. 1, p. 26.
[110] Public Service's Response Comments, p. 9.
[111] Staff's Comments, p. 19.
[112] *See* Staff's Comments, p. 19.

higher rate impacts than the Company's calculations suggest.[113] Given the importance of maintaining affordability, the Commission must consider these costs to customers more generally and not limit our consideration to the NPV comparison of the various resource portfolios.

105. An example of a cost to customers that does not explicitly appear in the NPV considerations is the likely cost of curtailments that the modeling fails to capture. Although the NPV estimates do include the costs of curtailments included in the modeling, the Company admits as discussed above that the model's curtailment forecasting is "more a 'best possible case scenario' than a realistic expectation of what would occur in real time operations."[114] Public Service notes that "a large percentage of curtailment" is caused by perturbations in the system from transmission issues or reliability events and that these curtailments "are not captured in the model."[115] The curtailments resulting from transmission issues are especially concerning given that under the UPP the Company will be connecting vast amounts of new renewable generation years before most of the associated transmission upgrades can be constructed.[116] The Company indicates that while the transmission investments are being built, Public Service will maintain reliable service using tools such as curtailments and redispatch.[117] Thus, the NPV calculations do not reflect significant amounts of curtailments that the modeling fails to capture, but these missing curtailments will result in additional costs that customers must pay.

106. The Alternative Portfolio cuts modeled curtailments from 15 percent in the UPP to 5 percent,[118] and curtailments that the model does not capture will likely also be reduced due to a decreased reliance on yet-to-be-built transmission and an increased investment in storage. By way

[113] Staff's Comments, p. 19.
[114] 120-Day Report, p. 95.
[115] 120-Day Report, p. 95.
[116] *See* Staff's Comments, pp. 43-44.
[117] 120-Day Report, p. 134.
[118] *See* Staff's Comments, p. 49.

of analogy, Public Service predicts that the UPP will have 6,043 GWh of curtailments in 2028,[119] but the Alternative Portfolio is only predicted to have 1,629 GWh of curtailments in 2028.[120] It is reasonable to assume that curtailments that the model fails to capture will follow similar trajectories resulting in significant additional costs savings in the Alternative Portfolio.

107. Put simply, the Alternative Portfolio will achieve the state's ambitious clean energy targets while mitigating the risk that ratepayers will be required to pay for resources that have less incremental value because they are significantly curtailed.

108. Another category of costs that does not appear in the NPV calculations are the potential costs associated with Company-owned gas generation assets, including construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded. On this last point, several parties including UCA, WRA, Conservation Coalition, and Boulder, as well as numerous public comments, raised concerns that the new gas resources will become stranded assets. The Alternative Portfolio is again preferable to the UPP in this regard because it contains a substantial decrease in Company-ownership of new gas capacity. Specifically, the UPP contains 628 MW of new build gas resources, all of which are Company-owned.[121] The Alternative Portfolio contains 669 MW of new build gas resources, but of this 669 MW, 219 MW is a PPA resource with a 20-year term.[122] By diversifying the ownership of the gas resources, the Alternative Portfolio reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources.

[119] Public Service's Response Comments, Attachment 2, p. 1.
[120] 120 Day Report (Appendix T), p. 23.
[121] Public Service's Response Comment, p. 9.
[122] 120-Day Report (Appendix S) Rev. 1, p. 26.

109. Finally, yet another cost that is not included in the NPV estimates is the risk that a larger, more sprawling resource portfolio like the UPP will eliminate opportunities to take advantage of future technology developments or reductions in price in some of the newer technologies. As discussed more below, acquiring a smaller portfolio of resources in this Proceeding creates more optionality in future proceedings for efficiencies and cost savings, including through a more robust use of demand side resources. In other words, the Alternative Portfolio reduces the risk that customers will pay for generation and transmission resources that could have been avoided through better use of developing technologies.

110. As we consider costs, we believe that least-cost options presented in the Phase II report may be unworkable for Colorado. We find unpersuasive arguments raised during Phase II that the Commission should select the Least Cost Portfolio. While the Least Cost Portfolio is slightly less expensive on a NPV basis than the Alternative Portfolio,[123] the Company has raised reliability concerns with the portfolio because it does not include the strategically located gas resources the Company asserts are necessary for transmission support.[124]

111. Similarly, we reject arguments that selecting a larger portfolio to reduce emissions at any cost is appropriate. It is critical that we examine costs and emissions together, and in conjunction with reliability as required by statute. Not only is the diverse technical makeup of the Alternative Portfolio needed for the reliability needs raised by the Company and discussed more below, but because of the increase in storage in the Alternative Portfolio, modifying the CEP to move forward with this portfolio also allows further development with not only load but storage capacity that could help increase efficiencies and reduce costs in the future. In addition,

[123] The Least Cost Portfolio has a PVRR of $43,984 million, which is $13 million less than the Alternative Portfolio's PVRR or 43,9997. (120-Day Report, p. 38; 120-Day Report (Appendix S) Rev. 1, p. 26).

[124] 120-Day Report, pp. 39-40; Public Service's Response Comments, p. 29.

overinvesting in the system could price electricity out of competition with other fuels, jeopardizing beneficial electrification efforts.[125] To help ensure that Colorado can continue to decarbonize all sectors of the economy—many parts of which will rely on the electrical system as the backbone of the transition—it is essential to provide electrical service at a reasonable cost and rate impact.

112. Finally, CRES and certain public commentors note that Public Service's NPV cost numbers were calculated using the Company's weighted average cost of capital (WACC) as the discount rate, and they urge the Commission to use a lower discount rate. CRES argues that using the WACC as the discount rate will have the effect of discounting future fuel and other costs sharply. Moreover, CRES states that in enacting SB 23-291, the legislature has directed the Commission in C.R.S. § 40-2-139 to use a discount rate for future fuel costs that does not exceed the long-term rate of inflation. CRES recommends that the Commission direct the Company to resubmit the NPV values in accordance with what is now Colorado law.[126]

113. We note that the appropriate use of discount rates was litigated in Phase I. The Phase I Decision put forward a compromise to help mitigate the substantive concerns raised by CRES, requiring Public Service to provide in Phase II the annual nominal cash flows associated with each portfolio so that the parties and the Commission could calculate the NPV calculation using various discount rates.[127] As such, this Commission believes it is important to understand the potential cost and other resource choice impacts that might occur at lower discount rates, but

[125] Numerous public commenters argue that the Alternative Portfolio is more expensive than the UPP on a dollars per MW basis. This argument only looks at the nameplate capacity of the respective portfolios and does not account for important distinctions in how different resources contribute to the electrical system. For example, a 300 MW solar facility will be of no value to the electrical system after the sun sets. A 300 MW solar plus storage facility, however, is able to help serve load after the sun sets and, in this way, can be more useful to the electrical system, even though it has the same nameplate capacity as the solar facility. Thus, the addition of storage resources to a portfolio can contribute value in ways that are not reflected in the amount of nameplate capacity.

[126] CRES's Comments, pp. 2-3.

[127] Phase I Decision, ¶ 211.

declines to upset the compromise position we adopted in the Phase I decision particularly since the Company did provide the requested Excel worksheet as Appendix W to the 120-Day Report.

114. Likewise, we reject CRES's argument that the Commission is required in this Phase II process to use an alternative discount rate per SB 23-291's amendment to C.R.S. § 40-2-139, which would further extend the Phase II process with additional modeling and process by relitigating issues resolved in Phase I. CRES is correct that, going forward, the requirement imposed by the amended § 40-2-139, C.R.S. imposes a duty on the Commission that, if it relies on the use of a discount rate when calculating NPV of future carbon-based fuel costs, the rate must not exceed the long-term rate of inflation. However, the law does not consider or include the necessary Phase I and II process or other clarifications.

115. A law is presumed prospective unless the legislature "clearly and unequivocally expressed" [128] intent for the statute to apply retrospectively. Generally, when the cause of action "accrues prior to the effective date of an amending statute," the prior statute controls.[129]

116. Here, Public Service filed its application in this Proceeding in March 2021. At that time, and at the time of the Phase I order, the statute did not include the updated language, which went into effect in August 2023. The party evidence and record overall, including the expectation of the Company when it filed the application, were set well before the 2023 legislative session. The issue was fully concluded through the Phase I Decision issued in 2022. To change the required scope of the considerations at this late phase is not required and counters long-standing precedent.[130]

[128] Edelstein v. Carlile, 33 Colo. 54, 57, 78 P. 680, 681 (1904)

[129] United Bank of Denver Nat. Ass'n v. Wright, 660 P.2d 510, 511 (Colo. App. 1983*);* Diversified Veterans Corp. Ctr. v. Hewuse, 942 P.2d 1312, 1314 (Colo. App. 1997) (holding that the imposition of penalties involves substantive rights and liabilities and is therefore governed by the law in effect on the date of the party's injury).

[130] *See, e.g.*, United Bank of Denver Nat. Ass'n v. Wright, 660 P.2d at 511.

117. Phase I is complete and has always been the appropriate phase for determination of the applicable discount rate. In enacting its statute in 2023, the Legislature is presumed to understand this process, and the Commission certainly will be required to apply the statute in future ERP Phase I decisions that direct the necessary considerations of discount rate determinations. The Commission is not, however, required to alter its Phase II process and extend already tight timelines for further modeling, analysis, and to expand the record. Indeed, if it did, these actions would potentially put at risk the time-sensitive bidding process.

118. Nevertheless, as the Commission did in its Phase I order in considering updates to statute subsequent to the 2021 ERP application filing by directing the Company to include the social cost of methane in its Phase II information, the Commission is in no way precluded from recognizing the statutory considerations and discussing the spirit and application based on the record. The Commission generally has a broad delegation of power to regulate utilities from the Colorado legislature.[131] Where the legislature has not directly prohibited the Commission from considering certain factors, the Commission generally can exercise its power over rates and utilities as it sees fits.[132] Specifically, when approving resource plans, the Commission can consider "other relevant factors, as determined by the commission."[133] The legislature grants the Commission broad power here to determine what factors are appropriate to use to compare bids in a resource plan.[134] Recognizing these statutory provisions, the record here indicates that the Alternative Portfolio would still be the most appropriate selection.

119. No parties to this Proceeding submitted analysis during Phase II showing the PVRR of various portfolios using a lower discount rate, although certain public commentors submitted

[131] *See* City of Montrose v. Pub. Utils. Comm'n*,* 629 P.2d 619, 622 (Colo. 1981).
[132] *See* § 40-3-102, C.R.S.
[133] § 40-3.2-106(3)(c), C.R.S.
[134] § 40-3.2-106(3)(c), C.R.S.

analysis regarding the impact of different discount rates on the NPV of fuel costs. Regardless, even assuming that certain that a lower discount rate makes the Alternative Portfolio more expensive on a NPV basis compared to the lower dispatchable portfolio, the no new gas portfolio, and the no gas portfolio, this does not justify the selection of a different portfolio. First, the Commission is still prohibited from selecting a portfolio that fails to protect reliability. Public Service states in its Response Comments: "neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law."[135] Public Service has also raised concerns with the reliability of the lower dispatchable portfolio. Moreover, while one of the enumerated statutory factors is the cost on a NPV basis, the statute permits the Commission to also consider other relevant factors. One such unenumerated factor the Commission is considering is the cost to customers more generally. Through this lens, the lower dispatchable portfolio, the no new gas portfolio, and the no gas portfolio all require significantly more resource acquisitions in the short term that will have significant consequences for the affordability of electric service. This factor weighs in favor of granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio.

### 3. Reliability and resilience of the electric system

120. The statute also requires the Commission to consider the impact of the CEP on the reliability and resilience of the electric system and prohibits the Commission from approving a plan that does not protect system reliability. Based on modeling in this record, the Alternative Portfolio is just as reliable, if not more so, than the UPP.

121. As presented by the Company, gas-fired generation resources are a key factor in ensuring reliability. In response to arguments that the Commission should reduce the amount of

[135] 120-Day Report, p. 60.

gas resources, Public Service asserts that it "cannot become comfortable with any level of reduction in dispatchable resources."[136] In addition to the total amount of gas resources included in the portfolio, Public Service asserts that two gas resources within the UPP are strategically located and necessary to provide transmission support: Bid 989 in the Denver Metro area and a new gas resource in the Alamosa area. Regarding Bid 989, the Company states that it "is the only bid submitted that includes firm dispatchable generation providing supportive benefit to the transmission constraint" in the Denver Metro area.[137] Similarly, the Company notes that, after a 2026 retirement of an existing gas resource, there will be no firm dispatchable resources located in the San Luis Valley. The Company asserts that it is essential from a reliability perspective to continue to have firm dispatchable generation in the region.[138]

122. The Alternative Portfolio slightly increases the amount of gas resources included in the UPP and retains the two gas resources that Public Service argues are strategically located and necessary to provide transmission support.[139] The only modification the Alternative Portfolio makes to the gas resources in the UPP is to Bid 1000, which the Company does not flag as being necessary for transmission support.[140] Bid 1000 is a Company-owned project with two 200 MW combustion turbines (CTs). The Alternative Portfolio would eliminate one of the 200 MW CTs in Bid 1000 and replace it with a 219 MW CT (Bid 235) that is owned by an IPP. As set forth above, this change provides valuable diversification benefits that, among other things, reduces the risk of stranded assets that customers face from Company-owned gas resources. In addition, Public Service has raised no reliability concerns with Bid 235. Indeed, Bid 235 is included in the backup

[136] Public Service's Response Comments, p. 29.
[137] 120-Day Report, p. 39.
[138] 120-Day Report, p. 39.
[139] 120-Day Report (Appendix S) Rev. 1, p. 26. While the Alternative Portfolio replaces the UPP's Alamosa gas resource with a slightly larger gas resource that is also located in the Alamosa area.
[140] 120-Day Report, p. 29.

portfolio and is the only gas bid that the Company includes in its Prospective New Load portfolio.[141] Thus, the Alternative Portfolio maintains or increases the reliability of the UPP in that it retains the two strategically located gas resources, slightly increases the total amount of gas resources, and replaces a Company-owned gas resource with a PPA resource that the Company has found to be reliable.[142]

123. Furthermore, the Company ran both the Alternative Portfolio and the Preferred Portfolio (which closely resembles the UPP) through an "extreme summer" scenario that—according to the Company—"provides useful information on the reliability of the portfolios under extreme events."[143] Under this extreme summer scenario, the Alternative Portfolio performed better than the Preferred Portfolio.[144] Thus, we are left to conclude that the Alternative Portfolio is not only reliable based on Public Service's own metrics, it appears to be more reliable than the UPP.

124. Although the UPP and the Alternative Portfolio have comparable levels of gas-fired generation, we acknowledge the arguments from several parties and numerous members of the public that the Commission should only approve a resource portfolio with fewer or no new gas resources. We share their disappointment that the Phase II competitive resource solicitation failed to result in any viable portfolio with fewer gas resources and again urge the Company to come

[141] 120-Day Report, p. 55; Public Service's Response Comments, p. 27.

[142] Pursuant to the Phase I Settlement and the Phase I Decision, the model PPA for dispatchable resources was amended to, among other things, require that gas resources have backup fuel on site necessary to allow the facility to run continuously for a minimum of five days at maximum load on the alternative fuel. Firm gas transportation contracts could serve as a substitute for the requirement to have a backup alternative fuel on site. (Phase I Decision, pp. 106-06; 120-Day Report, pp. 122-23). In the 120-Day Report, Public Service confirms that "[a]ll bids that were advanced to EnCompass modeling are compliant with the requirement for either onsite backup fuel storage or firm gas transportation contracts" but that the model did not select the fuel oil storage bids due to economics. (120-Day Report, p. 125). The Commission reiterates its interest in having five days of backup fuel onsite for the new gas resources.

[143] 120-Day Report, p. 77.

[144] Corrected Table 19 of 120-Day Report, p. 1.

forward in future proceedings, including the 2024 JTS, with more developed demand side resources and other reliability solutions that do not involve new gas resources. As described above, the requirement to include at or near the amount of gas resources in the Alternative Portfolio stemmed from the Company's reliability determinations and their direct modifications to the modeling in Phase II, as a result. The Commission is disappointed that specific, locational reliability concerns were not clearly communicated in Phase I, which could have been informative to potential bidders and provided additional options.

125. We therefore find that granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio, including its gas resources, is in the public interest. First, SB 19-236 prohibits the Commission from approving a plan that does not protect system reliability. Thus, we cannot simply carve out from a modeled resource portfolio some or all of the firm dispatchable resources that Public Service maintains are necessary for reliability.

126. Other modeled resource portfolios with fewer gas resources than the Alternative Portfolio were presented by Public Service—including the Lower Dispatchable portfolio, the No New Gas portfolio, and the No Gas portfolio. None of these portfolios, however, represent a better option than the Alternative Portfolio. Public Service states in its Response Comments that "neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law."[145] In addition, we note the No New Gas portfolio and the No Gas portfolio are significantly larger and more costly than the Alternative Portfolio.

127. As for the Lower Dispatchable portfolio, it is much larger than the Alternative Portfolio (7,163 MW instead of 5,835 MW) and more expensive on a NPV basis ($45,315

[145] 120-Day Report, p. 60.

compared to 43,997).[146] Moreover, as compared to the Alternative Portfolio, the Lower Dispatchable portfolio simply reduces the amount of PPA gas resources by selecting a smaller CT (Bid 1061). The Company-owned gas resources are essentially unchanged.[147] In addition, the Company argues in its Response Comments that it has reliability concerns with Bid 1061.[148] Thus, on this record we find that the Alternative Portfolio is superior to the Lower Dispatchable portfolio, the No New Gas portfolio, and the No Gas portfolio.[149]

128. Even though we would have preferred selecting a portfolio with fewer or no gas resources, we find it useful to consider the total amount of gas resources in the context of what was originally anticipated in Phase I of this Proceeding. Based on the inputs and assumptions established in the Phase I Settlement, the modeling predicted that the competitive solicitation could lead the Company to acquire 1,372 MW of gas additions.[150] The vast majority of the parties in this Proceeding joined the Phase I Settlement, including CEO, WRA, and Conservation Coalition. Thus, we conclude that the 669 MW of gas resources in the Alternative Portfolio are well within the guardrails established in Phase I.

129. While we find on this record that the Alternative Portfolio and its gas resources are in the public interest, we acknowledge the numerous concerns that parties raised regarding how Public Service tested for reliability in the Phase II modeling and the manual adjustments the Company made regarding gas resources. In particular, we share the concerns raised by parties

[146] 120-Day Report (Appendix S) Rev. 1, pp. 26, 28.

[147] 120-Day Report (Appendix S) Rev. 1, pp. 26, 28.

[148] Public Service's Response Comments, p. 30.

[149] For similar reasons, we reject CIEA's arguments that the Commission select a portfolio that use the annuity tail instead of the replacement chain modeling. As between the Alternative Plan and the Alternative Plan with the annuity tail, the new 219 MW PPA CT (Bid 235) is replaced with three short-term extensions of existing PPA CTs, but the Company-owned gas resources remain essentially the same. The record before us better supports the reliability of Bid 235 as compared to the extensions of the existing PPA CTs. Moreover, because the annuity tail version is just a sensitivity, its projected emissions have not been reviewed by CDPHE.

[150] Public Service's Response Comments, p. 28 (citing Phase I Settlement (Attachment D), at Table 3 and noting that the 1,372 MW of gas additions is over a longer RAP).

such as Staff, COSSA/SEIA, and Conservation Coalition regarding the Company's reliability rubric.[151] We also question whether the Company adequately communicated to bidders the importance of strategically located gas resources. It is our expectation that the Company will strive to resolve these issues prior to the 2024 JTS. Nevertheless, while these concerns further support our decision to select a tailored resource portfolio, we are unconvinced that these concerns warrant additional Phase II modeling or the manual removal of gas resources from the modeled portfolios.

### 4. Future Technology Development

130. Another related factor that the Commission considers when evaluating the CEP is the impact of future technology developments. For instance, the Alternative Portfolio includes a much higher percentage of storage resources than the UPP. This significantly expanded level of storage may be critical to future efforts to incorporate still greater amounts of renewables without unreasonable levels of curtailments while reducing the need for gas resources.

131. Colorado's bold clean energy targets necessitate a rapid shift in the electrical system, which in turn requires us to think about our electrical system in a different way. We cannot attempt to build Colorado's future, low-emission electrical system by continuing to build the system as we have in the past. Simply building increasing amounts of generation resources as the UPP would do results in high curtailments and high costs. In contrast, modifying the CEP to include the Alternative Portfolio helps the Commission start building a different type of electrical system that takes advantage of developing technologies in several ways. Efficient and cost-effective planning of such a system will rely on a variety of components: flexible supply, flexible demand, participation in larger geographic markets, energy efficiency and acquisition of

[151] *See, e.g.*, Staff's Comments, pp. 29-30; COSSA/SEIA's Comments, pp. 14-15; Conservation Coalition's Comments, pp. 10-13.

clean resources. While other dockets are addressing regional markets, demand flexibility and energy efficiency, in this CEP we address clean resources and flexible supply, placing a greater emphasis on supply management through increased storage capacity. As an example, energy storage resources in the Alternative Portfolio represent 32 percent of new capacity, [152] compared to just 16 percent in the UPP.[153] In this way, the Alternative Portfolio marks the first step in a new approach to resource planning for a modern, efficient, and cost-effective grid.

132. In addition, the modification of the CEP to include the Alternative Portfolio results in a smaller, less aggressive resource acquisition. Although it is likely that our selection of a smaller resource portfolio in this Proceeding will result in a larger acquisition in the 2024 JTS, deferral of some of the new generation resources will also provide additional time for the Commission to better understand and take advantage of developing technologies that might reduce the cost of, or eliminate the need for, new generation and transmission resources. In this vein, the Alternative Portfolio's acquisition of a PPA gas resource reduces the amount of gas resources that Public Service would otherwise own.[154] This gives Public Service more flexibility if future technology improvements render gas resources unnecessary. Moreover, advancements in various types of distribution system management are particularly promising for ensuring that the distribution system is more capable of the dynamic load management that will be more important as beneficial electrification advances. The Commission also expects that more robust and innovative demand response programs will be a critical part of the future electrical system. As more items like electric vehicles, heat pumps, and heat pump water heaters come onto the grid, the management of these loads will become increasingly important, but also increasingly possible.

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[152] Staff's Comments, p. 11.
[153] Public Service's Response Comments (Attachment 1), p. 1.
[154] *See* 120-Day Report (Appendix S) Rev. 1, p. 26.

To ensure that the Commission is being good stewards of ratepayer funds, we need the Company and their planning processes to evolve away from overbuilding resources and instead look for ways to enable more dynamic management of both supply resources and demand resources.

133. Several parties similarly argue that the Commission should continue examining how new technological developments could be used to meet system needs instead of traditional generation and transmission investments. For instance, WRA suggests that the need for some of the Denver Metro transmission upgrades could instead be addressed by load management programs. WRA states that investment in transmission system upgrades to alleviate the Denver Metro constraint may be needed but recommends that the Company develop without delay load management programs in the metro area. WRA also recommends that the Company improve distributed energy resource (DER) programs and interconnection rules, with financial incentives to ensure the growing DER capacity provides benefits to the grid.[155]

134. Similarly, noting that the Company's proposal for metro Denver transmission upgrades was "significantly influenced by the lack of cost-effective bids [for generation] in the Denver metro area," COSSA/SEIA asserts that the Company should consider alternatives to conventional transmission upgrades, including non-wires alternatives such as virtual power plants (VPPs).[156] CEO likewise encourages the exploration of non-wires alternatives associated with the proposed upgrades in its new Distribution System Plan as well as additional details in the 2024 JTS.[157] CRES argues that with the new storage contained in the Preferred Portfolio, together with the fact that long-term storage technologies are evolving quickly, the Commission should not

[155] WRA's Comments, p. 22.
[156] COSSA/SEIA's Comments, pp. 22.
[157] CEO's Comments, pp. 29-30.

approve the proposed gas resources until Public Service has gained significant experience operating its system with the large amount of storage that will be added in the coming years.[158]

135. Staff asserts that Public Service never mentioned the possibility of demand side or other generation solutions to alleviate the $2.1 billion in transmission in the Denver Metro area. Staff notes that demand response solutions, aggregation of customer-sited generation and storage, and the use of electric vehicles to deliver grid benefits are being discussed in the Commission's Distribution System Plan proceedings and VPP Miscellaneous Proceeding. Staff argues that it is unclear whether solutions such as Time-of-Use rates, critical peak pricing, additional demand response, VPPs focused on this period, managed charging, Vehicle-to-Grid programs, strategically located storage at Community Solar Gardens, etc. could prove to be more cost-effective solutions than what the Company proposes.[159]

136. Future development also implicates changing needs for workforce labor and development. Despite the many positive attributes of the Alternative Portfolio, we have not lost sight of best value regarding employment of Colorado labor and the impacts the Alternative Portfolio will have on the long-term economic viability of Colorado communities.[160] As set forth more below, the 120-Day Report assigns a BVEM score to each portfolio and the Alternative Portfolio's BVEM score is slightly lower than the UPP's BVEM score. Although it is disappointing that the Alternative Portfolio has a lower BVEM score, just as deferral of some of the new generation resources will provide additional time for the Commission to take advantage of developing technologies, the Alternative Portfolio allows time for better evaluation of BVEM for those resources that will be acquired in future solicitations. Notably, the BVEM scores appear

[158] CRES's Comments, p. 2.
[159] Staff's Comments, p. 41.
[160] *See generally* § 40-2-129(1)(a), C.R.S.

to track to some degree with the percentage of utility ownership, so as IPPs prepare for future solicitations, they should take special care to improve BVEM performance to ensure that in future solicitations the Commission does not see lower BVEM scores as a reason to disturb the ownership balance between the utility and IPPs. Ultimately, we believe that the positive attributes of the Alternative Portfolio, including cost, emissions reductions, reliability, and the ability to better address future technology developments and transmission concerns, outweigh the lower BVEM score.

137. In sum, the prospect of future technology developments weighs in favor of modifying the CEP to include the resources in the Alternative Portfolio. The composition of the Alternative Portfolio itself with the large amounts of storage will likely be key for the future low emissions electrical system. Likewise, the more tailored acquisition of resources provides the Commission with more opportunities to evaluate quickly advancing technologies such as distribution management and new demand response programs and balances the risk that some of these new technologies could reduce the need for future generation and transmission investments.

**5. Transmission Concerns**

138. The transmission concerns that have arisen in Phase II are another factor that contributes to the finding that granting Public Service authority to move forward with acquiring the resources in the Alternative Portfolio is necessary for the public interest. The Company presents several categories of transmission costs, but all are overshadowed by the $2.2 billion in investments for transmission network upgrades to the Denver Metro area.[161] In Phase I of this Proceeding, the Company identified a need in the Denver Metro area, but only estimated the need

[161] 120-Day Report, p. 130.

at a capital cost of “approximately $250 million”.[162] Therefore, the Phase II modeling did not consider the new and significantly larger cost or how to minimize or avoid it as part of the resource selection process. Moreover, as noted above, the majority of the transmission investments are not scheduled to be completed until 2030, years after many of the resources in UPP would otherwise come online,[163] exacerbating concerns regarding both the modelled and actual levels of curtailments that will occur in the UPP.

139. As discussed in more detail elsewhere in this Decision, several parties raise concerns about the $2.2 billion investment in transmission upgrades that Public Service states is necessary for the Denver Metro area and question whether the selection of resources could be better optimized to reduce the transmission upgrades. For example, Staff states that there “seems to be a fundamental problem that the modeling process does not integrate transmission planning in a meaningful way” and notes that Public Service “has not provided any analysis of the amount and type of metro area generation that would be needed to reduce this transmission network upgrade cost or the amount by which it could be reduced.”[164] Staff argues that the $2.2 billion surprise raises several questions including whether the transmission costs would be substantially different under any other generation portfolio, whether there are cost effective Denver Metro bids, and whether demand side or other generation resources could reduce the overall cost and need for the transmission network upgrades.[165]

140. Among the other parties that raise transmission concerns, CEC argues that the estimated $2.2 billion in transmission upgrades for the Denver Metro area is “shocking” and notes that this current estimate is almost nine times larger than the estimate provided in Phase I. CEC

[162] HE 107 p. 50-51
[163] Staff’s Comments, pp. 43-44 (citing Appendix Q to the 120-Day Report).
[164] Staff’s Comments, p. 40.
[165] Staff’s Comments, pp. 39-41.

asserts that this change fundamentally alters the facts the Commission and stakeholders relied on in Phase I.[166] UCA similarly argues that in the Preferred Portfolio Public Service intertwines generation and transmission projects to provide a circular basis for one another, which significantly expands Company ownership, costs, and capacity beyond what was contemplated in the Phase I Settlement.[167]

141. In the 120-Day Report, the Company cites several factors driving the need for large investments in the Denver Metro area, including population growth, the scale and location of new generation that the Company is acquiring in the Preferred Portfolio, and the lack of cost-effective bids in the Denver Metro area.[168] In its Response Comments, Public Service recognizes that "additional work remains to better integrate transmission and generation planning" but argues against the idea that material cost savings could be obtained with further analysis of the transmission costs or tweaks to the resource portfolio.[169] As support, the Company notes that a 30 percent reduction in the size of the resource portfolio only results in a 20 percent reduction in modeled transmission costs.[170]

142. The large and unexpected costs of the transmission investments, the timing of the investments compared to the associated generation, and the analysis that resulted in the proposed transmission investments all support the selection of the Alternative Portfolio. The costs associated with curtailments is discussed above, but the UPP creates a timing mismatch in which the majority of the transmission resources will be put into service years after the generation resources. In addition, we share Staff's questions as to whether alternatives exist that could reduce

[166] CEC's Comments, pp. 5-7.
[167] UCA's Comments, pp. 11-15.
[168] 120-Day Report, pp. 131-32.
[169] Public Service's Response Comments, pp. 68-69.
[170] Public Service's Response Comments, p. 69.

the overall costs and need for the network upgrades. While we cannot determine on this record whether the transmission network upgrades in the Denver Metro area will be necessary in the future,[171] the Alternative Portfolio defers certain resource acquisitions. At the very least, the deferrals provide more opportunities to further evaluate the proposed transmission network upgrades and enable the Commission – and Colorado as a whole – to have greater confidence that the acquisition of new resources minimizes transmission investments and is in the public interest.

### 6. Conclusion

143. Granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio instead of the UPP will likely reduce costs to customers, especially when the Commission considers costs more generally. Such costs include those that are likely to result from the curtailments that the model fails to capture and the potential future costs associated with Company-owned gas resources in the UPP (*e.g.*, decommissioning). At the same time, the Alternative Portfolio is just as reliable as the UPP, and perhaps more so. While the modeling shows that the UPP achieves greater emissions reductions than the Alternative Portfolio, the Alternative Portfolio still exceeds the state's ambitious clean energy targets, while leaving open the possibility for more cost effective emission reductions in the future. Furthermore, the emissions reductions in the UPP, and especially the interim emissions reductions, appear to be optimistic given the likely impact of curtailments that the modeling presented in the 120-Day Report does not fully incorporate. Finally, pursing a smaller, more tailored portfolio of resources is necessary for the public interest because it creates an opportunity to investigate how to better optimize transmission upgrades during resource selection and provides more opportunities to take advantage of

[171] While the estimated cost of the transmission investments is still quite large in Alternative Plan, it is approximately $397 million less than the associated transmission investments in the UPP ($2,353 - $1,956 = $397). (*Compare* Public Service's Response Comments, p. 9, *with* 120-Day Report (Appendix S) Rev. 1, p. 26.)

developing technologies that might reduce or eliminate investments in traditional generation and transmission assets. Given the point in this Proceeding in which the significantly higher transmission costs were disclosed and the opportunity to take advantage of other technologies to limit ratepayer expenses, including the UPP in the approved CEP cannot be found to be in the public interest, as the UPP leaves too many unanswered questions and opportunities for optimization still on the table. As discussed throughout this decision, modifying the CEP by including the Alternative Portfolio is necessary to ensure the plan is in the public interest.

144. To reach an approved CEP that meets Colorado's needs, we find that modification of the presented CEP to include the Alternative Portfolio is necessary to ensure the approved CEP is in the public interest. With its CEP activities—including the Coal Action Plan that is critical for reducing emissions—and the plans for workforce transition and community assistance, the modified CEP moves Colorado significantly forward in its clean energy transition.

## F. Transmission

### 1. Phase II Changes in Transmission Investments

145. In Phase I of this Proceeding, Public Service explained that it would need to make transmission investments in four areas to accommodate the new generating resources to be procured: 1) Denver Metro network upgrades, 2) grid strength reinforcement, 3) reactive power/voltage support, and 4) generator interconnections. At that time, Public Service provided a "preliminary and illustrative" cost estimate of $250 million for the Denver Metro upgrades, and a "rough" estimate of the combined costs for voltage support and grid strength of $150 to $250 million.[172]

[172] Hearing Exhibit 107, Direct Testimony and Attachments of Hari Singh, pp. 50-59.

146. In the 120-Day Report, the Company states that the transmission analysis it conducted to support the CEP is its most thorough transmission analysis for an ERP ever, involving numerous power flow studies, scenario modeling and "tabletop exercises" to develop project scoping and cost estimates. The Company states that 1) the scale and (largely remote) location of the new generation the Company will procure via this ERP, 2) the planned generation retirements the ERP entails, and 3) the lack of bids for new or existing generation located within the Denver Metro area transmission constraint all combine to require significant evolution of, and investment in, the transmission system to maintain reliable delivery of power to load centers.[173]

147. More specifically, the Company states that its existing substations lack the space for expansions necessary to eliminate overloads and expand the system's capacity, and that it has identified significant needs for new substations and new transmission lines. Moreover, it states that siting, permitting, and the need for extensive undergrounding in the Denver Metro area add cost and complexity to many of the network upgrade projects it has identified. Given these siting challenges, the Company states that its planning approach has been to create long-term ratepayer value by considering not only what upgrades are needed for its Preferred Portfolio, but also designing to accommodate future renewable development and growth in electricity demand.[174]

148. The Phase II cost estimates for grid strength/voltage support and the MVLE are consistent with the estimates for those costs in Phase I of this Proceeding. However, the Company adds a new, previously unreported category of transmission investments in Phase II—the San Luis Valley (SLV) network upgrades with an estimated cost of $176 million. In addition, in Phase II the estimated costs of the Denver Metro upgrades increase from $250 million to $2,146 million.

[173] 120-Day Report, pp. 128-134.
[174] 120-Day Report, pp. 128-134.

While Public Service asserts that its Phase II costs are not CPCN-level estimates, the Company states that its "process improvements" give it a higher confidence in these estimates than in those provided in previous ERPs.[175]

149. The Company claims that the need for Metro Denver upgrades have greatly expanded in Phase II and that the Phase II analysis identified substantial network upgrades needed within the SLV as well. The Company states that "[w]hile the smaller portfolio of transmission projects contemplated in Phase I may have alleviated transmission overloads within a short time window, the customer value of a smaller transmission portfolio would be quickly overwhelmed by additional load growth and resource acquisitions, requiring costly and difficult upgrades to new transmission facilities."[176] The Company stated reasons for the higher costs of the transmission investments include the following: siting and permitting challenges and the need for undergrounding many facilities in the Denver Metro area, the scale and location of new generation that will be acquired in this Proceeding, and the lack of cost-effective generation bids in the Denver Metro area.[177]

### 2. Party Comments

150. Staff reiterates that Public Service's transmission power flow analysis—conducted at the tail end of the Phase II modeling—estimates that almost $3 billion in transmission investment is needed to support the Preferred Portfolio (in addition to the approximately $1.7 billion investment recently approved in the CPP). Staff states that this estimated $4.5 billion in transmission investments is perhaps "Staff's largest concern with the Company's Preferred

[175] 120-Day Report (Appendix Q), p. 3.
[176] 120-Day Report (Appendix Q), p. 11.
[177] 120-Day Report (Appendix Q), p. 12.

Plan."[178] Staff reviews the Company's explanation of the necessary transmission upgrades but states that it is left with more questions than answers. Staff recommends that 1) the Commission make clear that "the Commission is in no way approving the transmission projects presented and described in the Report;" 2) the Commission add consideration of improved integration between transmission and resource planning and modeling to the recently-opened transmission pre-rulemaking docket 23M-0472E; 3) the Commission consider directing the Company to file a standalone transmission planning application; and 4) that the Commission consider options for implementing an independent transmission monitor.[179]

151. Staff acknowledges the concern that some of its recommendations could further delay transmission investments needed to deliver renewable energy. Given that many of the ISDs for the transmission investments are in 2029 and 2030, however, Staff argues that such delays might be avoidable.[180]

152. CEO, UCA, and CEC similarly criticize the transmission network upgrade proposals the Company presents in the 120-Day Report. For example, CEO recommends the Commission clarify that it is not providing a presumption of prudence on the proposed Denver Metro transmission network upgrades until additional information is provided. Specifically, CEO recommends the Company provide more information on the degree to which upgrades are necessary for reliability, as compared to planning for future growth.[181] UCA complains that the Company did not inform the Commission in the CPP proceeding that additional billions of dollars would be needed to deliver power from the CEP and states that had it

[178] Staff's Comments, p. 8.
[179] Staff's Comments, pp. 44-45.
[180] Staff's Comments, p. 45.
[181] CEO's Comments, pp. 29-30.

been aware of the magnitude of the transmission upgrade needs the Company now claims, it would have approached the proceeding differently.[182]

153. In contrast, other parties such as CIEA and COSSA/SEIA generally support the Company's proposed transmission investments.[183] In fact, COSSA/SEIA suggests that the transmission investments should be designed to accommodate continued growth in renewable energy development.[184]

154. In its Response Comments, Public Service maintains that transmission projects will be necessary for any generation portfolio to achieve the aggressive emission reductions the State requires.[185] In response to party comments recommending that the Commission not provide final approval of the network upgrade projects, the Company notes that it has not sought such approval, and reiterates its recommendation that the Commission schedule a Commissioners' Information Meeting (CIM) on CEP-related transmission in the first quarter of 2024 where the Company can further detail its broader transmission plans and analysis, and answer Commissioner questions. Following this, the Commission and parties can vet transmission projects through CPCN filings.[186]

155. The Company urges the Commission to deny the Staff recommendations to require a transmission planning proceeding and an independent transmission monitor. Public Service claims that "[t]hese recommendations are vague and would unnecessarily slow down the energy transition by requiring parties to expend valuable time and resources on processes with little, if any, incremental benefit."[187]

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[182] UCA's Comments, pp. 14-15.
[183] *See, e.g.*, CIEA's Comments, pp. 19-20.
[184] COSSA/SEIA's Comments, pp. 20-21.
[185] Public Service's Response Comments, pp. 65-66.
[186] Public Service's Response Comments, pp. 66-67.
[187] Public Service's Response Comments, pp. 67-68.

156. The Company expresses strong disagreement with Staff's suggestion that generating resources should be delayed to future ERPs in recognition of the time it will take to put the new transmission assets into service (and the likely curtailment this will cause). The Company argues that the State's policy objectives do not allow for this delay, and it encourages the Commission to approve the UPP now. It claims that delaying approval of generation assets will only result in increased bid prices for generation and increase both the cost and siting difficulties for transmission.[188] Public Service further argues that using tools such as curtailment and redispatch in the short term as transmission buildout is completed is superior to delaying the acquisition of resources.[189]

157. Responding to party arguments that some of the transmission upgrades are unnecessary, the Company notes that none of these parties conducted detailed transmission planning analyses and refers to their contentions as conjecture. The Company asserts that the transmission portfolio is a reasonable set of solutions and states that it sought to upgrade existing transmission facilities wherever possible instead of constructing new greenfield transmission lines.[190]

### 3. Findings and Conclusions regarding Transmission

158. We share the serious concerns expressed by parties regarding the large, unexpected cost increases in transmission investments. After nearly three years of process, it was incredibly frustrating to see such a major failure of planning and estimating come to light so late in this Proceeding, upending the understandings of this Commission and many of the parties about the cost to integrate resources associated with this solicitation. Public Service will need to improve

[188] Public Service's Response Comments, pp. 72-73.
[189] Public Service's Response Comments, pp. 73-74.
[190] Public Service's Response Comments, pp. 70-72.

its transmission modelling and cost estimation processes in in future ERP proceedings to allow the Commission and relevant stakeholders a better ability to assess the critical links between generation and transmission resources. As noted above, the concern around transmission that arose in Phase II of this Proceeding was one of the factors that compelled us to select a smaller, more tailored resource portfolio.

159. In addition, the Commission emphasizes that the proposed transmission network upgrades, grid strength reinforcements, and reactive power/voltage support investments presented in the 120-Day Report are not part of the approved CEP. We are neither approving (or denying) these transmission actions here nor entitling the investments to any sort of presumption of prudence (or prejudice). Substantially more process will be required to fully assess the need for, alternatives to, and cost of remedial actions on the transmission grid in light of significant transition that this Proceeding initiates. Not only does the Company note that it is not seeking approval of those actions here, but the Commission has made clear it is modifying the CEP such that these actions are still to-be-determined with possible alternative solutions.

160. Moreover, as presented, the transmission network upgrades appear designed to accommodate future renewable development and growth in electricity demand, not *just* the CEP and its emissions reduction goals. Likewise, the alleged need for some of the proposed transmission upgrades may simply be the result of an aging system and changing dynamics. Though prudency only attaches to the "approved CEP," Company filings continue to emphasize that the transmission network upgrades presented here are not part of its CEP.

161. In the context of the shocking cost increases associated with the new transmission and concerns regarding the analysis and vetting of the proposed alternatives to the transmission investments, the Commission agrees with Staff that we simply do not have enough information or

reliable modeling to authorize the spending on another $2.8 billion in transmission investments at the current time.[191] While the Commission recognizes that a prudency determination was not sought by the Company in this Proceeding, we are wary to approve a suite of resources that all but lock in the future need for significant additional future system expenses without first vetting alternatives to mitigate those costs. The Commission needs to see a more holistic picture of the various transmission projects arising from this Proceeding, including what investments are necessary and how the various transmission investments work together with other system requirements and constraints. This additional review of the proposed transmission projects is necessary even if Rule 3206 technically would not require a CPCN for some of the individual transmission projects in other circumstances. Accordingly, we waive Rule 3206 as to the transmission projects arising from this Proceeding; we emphasize that it is incumbent upon Public Service to provide a fulsome and comprehensive description of all transmission projects necessary to accommodate power delivery and maintain reliable service from the approved CEP. Thus, the Company is requested to bring forward one or more CPCN or other filings regarding transmission projects raised in this Proceeding. However, and particularly given our emphasis that selecting the Alternative Portfolio presents the opportunity that not every transmission project raised will ultimately be pursued, we leave it to the Company's discretion on how best to present this type of analysis to the Commission; *i.e.,* both in timing and type of filings made, but also with regard to the number or combination of filings.

162. The Commission does not oppose the Company's offer in its Response Comments to make a presentation on expected transmission requirements in a CIM. As a general matter, we are particularly interested in additional information regarding the differences in transmission plans

[191] Staff's Comments, p. 45.

between the UPP and the Alternative Portfolio as well as any explanation the Company can provide regarding the failure to better anticipate the significant transmission needs in the Denver Metro area. Likewise, the Commission is interested in learning from Public Service how the Company's planning processes will improve and any innovative ways to approach future ERP proceedings so that the optimization of costs includes transmission investments, and to avoid similar major discrepancies between Phase I and Phase II expectations presented in modeling. Nevertheless, we recognize that when the Company proposed the transmission CIM, it did so in the context of the UPP rather than the Alternative Portfolio. Given the significant changes associated with the Alternative Portfolio and timing concerns with the upcoming filing of the 2024 JTS, we refrain from directing a transmission CIM at this time but invite the Company to determine the appropriate time and forum to address our concerns.

163. In addition, we find merit in Staff's proposal that the scope of Proceeding No. 23M-0472E (*i.e.*, regarding review of the provisions addressing transmission CPCN and planning in the Commission's Rules Regulating Electric Utilities, 4 CCR 723-3, in anticipation of future rulemaking) should be specifically defined to include consideration of improved processes for integrating transmission planning into generation resource plan proceedings and modeling. It is reasonable to expect that a previously unknown $2 billion in additional expenses is an important variable to optimize around by reevaluating what different resource acquisition decisions would or could have been made to bring the entire portfolio of resource and transmission needs to a reasonable and optimized cost for ratepayers. As appropriate we will address these considerations in the context of Proceeding No. 23M-0472E, including through future order in that proceeding.[192]

[192] Staff and interested stakeholders are encouraged to bring forward proposals in the context of that proceeding. The Commission will address any necessary direction directly in the context of the pre-rulemaking proceeding.

164. We similarly find merit in Staff's recommendation to consider options for implementing an independent transmission analyst. The Commission sees value in having some independent transmission and power flow modeling expertise among Staff, CEO, and UCA with which the Company could collaborate. The presence of such outside expertise could help accelerate approvals and lessen the overwhelmingly negative reactions of "surprises," such as the $2.2 billion in transmission network upgrades for the Denver Metro area. We see the primary role of this independent transmission analyst as building up the analytical capabilities of parties, particularly Staff, UCA, and CEO, regarding power flow modeling and other transmission issues.

165. Accordingly, we direct Staff to initiate a stakeholder process with UCA and CEO and in conferral with Public Service. The objective of the stakeholder process would be for Staff to bring forward a scope of work for hiring an independent transmission analyst. While we will leave it to the stakeholders to work through the details, this scope of work could be based on the IE contracting approach the Commission uses in ERP proceedings in which the Company contracts with the outside expert. Our expectation is that the analyst would work integrally with Staff. Ultimately, however, the independent transmission analyst must maintain independence from the Company.

166. Regarding timing, Staff should bring forward the proposed scope of work as soon as reasonably feasible but no later than through initial filings at the commencement of the 2024 JTS proceeding. Ideally, the independent transmission analyst could assist with the modeling in Phase I of the 2024 JTS. It would be ideal in Phase I of the process to have the help of an expert third-party to identify approximate quantities of certain resource types in targeted geographic areas to test assumptions about total costs for different portfolios, inclusive of both generation and transmission costs. We acknowledge the short timeframe this creates but find that time is of the

essence to ensure that the relevant state agencies have this type of expertise available during Phase I of the 2024 JTS to inform the parameters of the Phase II portfolios, given the shortcomings of this Proceeding.

167. As should be evident from our decisions on items such as the selection of the Alternative Portfolio and the directive for Staff to produce a scope of work for an independent transmission analyst, it is our expectation that the Company will look for better ways to model and analyze transmission costs in Phase I of the 2024 JTS. Part of these efforts should focus on mechanisms to provide reliable electrical service through dynamically managing both supply resource and demand resources—as opposed to simply building more generation and transmission resources.

168. We aspire for the independent transmission analyst discussed above to be engaged during Phase I of the 2024 JTS to bolster the analytical capabilities of Staff, CEO, and UCA regarding the integration of transmission and generation resources. However, given the possibility that the independent transmission analyst cannot be engaged in time for Phase I, as a backstop we direct Public Service to include certain portfolios in its direct case. Specifically, Public Service must present—at a bare minimum—one or more portfolios that examine minimizing transmission costs by increasing resources interconnecting in the Denver Metro area or using capacity on existing transmission lines, including capacity that will become available as thermal generating units retire. Broadly communicating the geographic areas for resource development anticipated to minimize transmission costs could also increase the likelihood of bidders to provide additional options in these target areas.

## G. Performance Incentive Mechanisms

### 1. Background and Party Comments

169. After the filing of the 120-Day Report, in Decision No. C23-0672-I[193] the Commission directed the Company to submit comments outlining a potential symmetric risk sharing mechanism that would apply to Company-owned projects. The goal of this project-specific mechanism would be to better align customer and utility incentives, treat Company-owned generation projects in ways that are at least somewhat closer to the risks that are routinely imposed on IPP projects, and to ensure reasonable costs for customers.[194] While the Commission required a response from Public Service, it also invited comments from the intervenors.[195]

170. On October 20, 2023, Public Service filed its Response to Decision No. C23-0672-I. Staff similarly filed a proposal on October 20, 2023, which UCA and CEC joined.

171. Public Service proposes two complimentary risk-sharing proposals or PIMs, with possible variations for both PIMs. The first is a cost to construct PIM intended to incentivize the Company to complete projects within its estimated capital expenditures that formed the basis of its Phase II bids. The Company proposes either (1) a dead band with sharing approach, or (2) a fixed capital cost approach. For either of these two approaches, the Company recognizes that the Commission could implement the PIM on either a project specific basis or on a portfolio basis.[196]

172. The second PIM is an "operational performance" PIM modeled after the Commission's suggested Levelized Energy Cost (LEC) metric identified in Appendix P to the 120-Day Report. Noting that the committed energy and weather adjustment provisions of PPA

[193] Issued October 6, 2023.
[194] Decision No. C23-0672-I, p. 3.
[195] Decision No. C23-0672-I, p. 4.
[196] Response to Decision No. C23-0672-I, pp. 6-7.

allow IPPs some flexibility in how much energy their projects produce, the Company argues that a 15 percent dead band around the Appendix P LEC is appropriate.[197] The Company further argues that the operational PIM should not seek to manage curtailments but that this is better addressed in the emissions reduction PIM.[198] In fact, the Company argues that any operational PIM should include curtailed volumes in the calculation of the LEC in part because this avoids creating a perverse incentive to favor Company-owned generation when determining which units to curtail.[199]

173. The Company asserts that the combination of these two PIMs should meet the Commission's expectation regarding cost discipline regarding both capital investment and operational performance.[200]

174. Under Staff's proposed PIM for utility-owned generation, Public Service would be required to recover the costs of Company-owned renewable generation assets entirely through the electric commodity adjustment (ECA) as opposed to base rates.[201]

175. Other intervenors suggest various other types of PIMs in their comments to the 120-Day Report. For example, Boulder's suggestions include a PIM for Company-owned projects that would use as a baseline the cost of seemingly lower priced bids as well as a PIM to address the capacity factors for gas resources.[202] COSSA/SEIA suggests that the Commission consider deploying a PIM that would incentivize the on-time construction and deployment of new

[197] Response to Decision No. C23-0672-I, p. 11.
[198] Response to Decision No. C23-0672-I, pp. 12-13.
[199] Response to Decision No. C23-0672-I, p. 13.
[200] Response to Decision No. C23-0672-I, pp. 1-2.
[201] Staff Response to Risk Sharing Mechanism, p. 14.
[202] Boulder's Comments, pp. 14-15.

transmission assets.[203] Conservation Coalition in turn proposes a mechanism in which the Company would bear any incremental costs for hydrogen conversion of its gas plants.[204]

176. In its Response Comments, the Company appears to argue that the cost to construct PIM should only be a fixed capital cost approach based on the total portfolio. Without much explanation, Public Service states that to facilitate approval of a PIM framework in this Proceeding, there should be no dead band for the construction capital cost PIM. Instead, the baseline should be set at the approved portfolio capital budget/point cost estimate.[205]

177. For the operational PIM, the Company argues in its Response Comments that the baseline should be adjusted to exclude the effect of construction capital expenditures in order to avoid such capital expenditures being subject to both PIMs. Public Service states that this is necessary to avoid double penalty or double reward.[206] In addition, the Company states that the evaluation period for projects subject to the operational PIM should occur on three-year intervals beginning with the first through third full calendar years of project operation. As an example, for a project with a commercial operation date of September 30, 2026, the evaluation period for the operational performance PIM would begin January 1, 2027, and extend through December 31, 2029. Public Service argues that this promotes administrative efficiency and better addresses annual variation in weather, maintenance patterns and other performance drivers.[207]

178. In contrast, Public Service vehemently opposes Staff's proposal, stating that "[t]he magnitude and ramifications of this proposed sea change are difficult to overstate."[208] Public Service asserts that Staff's PIM would "essentially deregulate generation in the state" in

[203] COSSA/SEIA's Comments, pp. 20-21.
[204] Conservation Coalition's Comments, pp. 16-17.
[205] Public Service's Response Comments, pp. 81-82.
[206] Public Service's Response Comments, p. 82.
[207] Public Service's Response Comments, p. 82.
[208] Public Service's Response Comments, p. 83.

that it would reconstitute the Company as an IPP in all but name.[209] The Company argues that Staff's proposal would increase the risks conferred to the Company with little incremental benefit and no opportunity to price that risk into its bids. Public Service asserts that, if implemented, Staff's proposal "would require the Company to reassess its project commitments, increasing the cost and delaying the delivery of this plan, or whatever is left of it."[210]

179. On December 19, 2023, Public Service filed its Response to Decision No. C23-0841-I, providing additional point costs and capacity factors data in connection with the Alternative Portfolio and setting forth the Company's proposed sharing percentages for the operational PIM in a non-confidential format.

### 2. Findings and Conclusions

180. The Commission appreciates that the Company has "sharpened its pencil" and is willing to "stand behind its pricing and performance metrics as bid."[211] Given the significant amount of Company-owned generation projects in the portfolio of resources Public Service will acquire,[212] this confidence and willingness to share risks is an important component of our decision to move forward with the Alternative Portfolio. In other contexts, costs, performance, or scheduling issues have increased costs for customers relative to the initial estimates the Company provided, and material changes to the cost and performance metrics of a project could impact the justification of the need determinations made in the ERP process.[213] More generally, competitive solicitation is the lynchpin of Colorado's ERP process, and a successful competitive solicitation

[209] Public Service's Response Comments, p. 83.
[210] Public Service's Response Comments, p. 86.
[211] Response to Decision No. C23-0672-I, p. 4.
[212] Of the 5,835 MW that the Alternative Portfolio contemplates acquiring, Public Service would own 53.7 percent of the capacity resources and 67.3 percent of the energy resources. (120-Day Report (Appendix S), Rev. 1, p. 26.)
[213] *See* Decision No. C23-0672-I, pp. 2-3.

relies upon some degree of certainty that, after winning at a lower price, bidders will not be able to materially increase the price of their bids without consequences. To date, the Commission has not had a mechanism in place to hold the Company to their bids and performance, in a similar way to the IPP contracts, which has increasingly become a point of concern. In Phase I of this Proceeding, the Company put forth a plan to convert the Brush Coal Plant to burn natural gas at a capital cost of $44 million. The Commission and parties relied upon the information provided by the Company to make decisions in Phase I of this Proceeding, broadly considered the Company's Coal Action Plan, which was agreed to be carried forward into the Phase II modeling. Several months later, the Company put forth a CPCN application to complete the conversion at the significantly increased cost of $85 million. The Commission finds a compelling need to ensure that the pricing relied upon during this Proceeding will not be significantly altered after the fact without a meaningful sharing of risk with the Company. The Company-ownership PIMs that Public Service proposes help ensure that the Commission is making informed resource acquisition decisions, promoting fairness amongst the bidders and the Company, and providing necessary protections to ratepayers.[214]

181. Accordingly, as part of the Commission's approval of the planned acquisition of Company-owned generations projects consistent with the Alternative Portfolio, we adopt a cost to construct PIM and an operational PIM for all Company-owned generation projects arising from this Proceeding.[215] These cost to construct and operational PIM are based on the Company's proposals, subject to the modifications detailed below.

[214] *See* Decision No. C23-0672-I, pp. 2-3.

[215] The cost to construct PIM applies to all Company-owned generation projects from this Proceeding, including Bid 1029. As set forth below, however, the operational PIM only applies to Company-owned LEC projects.

### a. Cost to Construct PIM

182. Starting with the cost to construct PIM, we reject the Company's arguments that the cost to construct PIM should be applied on a portfolio basis. Rather, the cost to construct PIM shall be a project-specific PIM for each Company-owned project in the Alternative Portfolio. Applying this PIM on a portfolio level would be inconsistent with how IPP bids are treated and contrary to the underlying principles of the competitive solicitation that each project must stand on its own.

183. The baseline for each cost to construct PIM will be the point cost for capital costs to construct the particular generation project that was used in the Company's Phase II bid. In its Response to Decision No. C23-0672-I, Public Service states that "each Company-owned bid has a point cost for capital cost to construct that can serve as a baseline for PIM evaluation purposes."[216] During the course of Phase II, the Company provided the point costs for all relevant Company-owned projects.

184. Under the cost to construct PIM, there would be a five percent dead band around the baseline in which Public Service earns no incentive or disincentive. Outside of the five percent dead band, however, the Company and ratepayers would share any cost overruns or savings based on three symmetrical tiers. Specifically, for a total variance of more than 5.0 percent through 10.0 percent above or below the baseline, 40 percent of the cost overruns or savings would be allocated to Public Service. For a variance of more than 10.0 percent through 15.0 percent above or below the baseline, 50 percent of the cost overruns or savings would be allocated to Public Service. For any variance above or below 15.0 percent of the baseline, 60 percent of the cost overruns or savings would be allocated to Public Service.

[216] Response to Decision No. C23-0672-I, p. 6.

185. The sharing percentage will be applied to the overage and not on the total project amount. Also, there will be no deduction due to the 5 percent dead band or any other previous tiers. For example, if a project with a $100 million point cost is actually constructed for $114 million, Public Service would incur a $7 million disincentive; *i.e.,* the 14 percent overage means that 50 percent of additional costs are allocated to Public Service (50 percent of $14 million is $7 million). The same calculation would be used if Public Service was able to construct the project for only $86 million. In that scenario, the Company would earn a $7 million incentive. Resolution of the appropriate PIM assessment (*i.e.* the calculation of any incentive or disincentive) will occur in the first rate case following the ISD of the relevant generation project.

**b. Operational PIM**

186. Turning to the operational PIM, the baseline will be the LEC for the relevant project set forth in the corrected Appendix P. The operational PIM will be applied on a project-specific basis. Except for LCC-based projects like standalone storage and gas, the operational PIM will apply to all Company-owned generation arising from this Proceeding. Regarding the exclusion of LCC-based projects, we find persuasive the Company's argument that including such project could have an unintended consequence of incentivizing the overuse of dispatchable resources in order to avoid penalties or to accrue incentives.[217]

187. The Commission rejects the 15 percent dead band that Public Service proposes for the operational PIM and will replace it with a 5 percent dead band around the LEC baseline. This narrower dead band is supported by—among other things—CIEA's Comments. CIEA asserts that the Company either exaggerates or obscures the true costs and risks of its proposal when compared to PPA arrangements. CIEA points out that IPPs have no dead band around their bid

[217] Response to Decision No. C23-0672-I, p. 12.

price and suggests that the Company should not have the benefit of a dead band either.[218] While we do not agree that removing the dead band altogether is appropriate, we agree with CIEA that the intent of the PIM is to set the Company's bidding risk on par with IPPs more readily. Establishing the mechanism here with a narrower dead band than proposed by the Company better aligns these goals.

188. Aside from the narrower dead band, the basic calculation structure for assessing the incentive or disincentive under the operational PIM would generally match the Company's proposal. Specifically, for variances of more than 5 percent through 10 percent above or below the baseline, 20 percent of the costs or savings would be allocated to Public Service. For variances of more than 10 percent through 15 percent above or below the baseline, 30 percent of the costs or savings would be allocated to Public Service. For variances of more than 15 percent through 20 percent above or below the baseline, 40 percent of the costs or savings would be allocated to Public Service. For variances of more than 20 percent through 25 percent above or below the baseline, 50 percent of the costs or savings would be allocated to Public Service. And finally, for any variance more than 25 percent above or below the baseline, 60 percent of the costs or savings would be allocated to Public Service.[219]

189. Regarding the timing of performance evaluations, the Commission agrees with the Company that performance evaluation for projects should be conducted on a three-year rolling average after the third full operational year is complete and on a similar cadence thereafter.[220]

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[218] CIEA's Comments (Attachment A), p. 5-6.

[219] *See* Public Service's Response to Decision No. C23-0841, pp. 2-3.

[220] In its Response Comments, Public Service provides the following example of this timing: "As an example, for a project with a commercial operation date of September 30, 2026, the evaluation period for the operational performance PIM would begin January 1, 2027 and extend through December 31, 2029." (Public Service's Response Comments, p. 82).

This approach will stagger the performance reviews so that a subset of projects (*e.g.*, all those with 2026 ISDs) is evaluated each year.

190. We similarly agree with Public Service's arguments that the baseline of the operational PIM should be adjusted to exclude the effect of construction capital expenditures in order to avoid such capital expenditures being subject to both PIMs.[221] Excluding the effect of construction capital expenditures is necessary to avoid double penalty or double reward.

191. In connection with the establishment of the operational PIM, all projects subject to the operational PIM in this Proceeding will receive cost recovery through the appropriate rider (RESA or ECA) from the ISD of the project until the project is rolled into base rates.

192. While we direct that the operational PIM as described above apply to all Company-owned LEC projects arising from this Proceeding, we recognize that certain considerations warrant further exploration in future proceedings. For instance, we invite interested stakeholders and the Company to explore whether an operational PIM could be crafted in which the baseline is derived from the project's estimated capacity factor as opposed to the estimated LEC. This would essentially exclude factors such as the capital construction costs and the Company's estimated WACC. We welcome a more robust consideration of this approach in the upcoming 2024 JTS.

193. Similarly, we reiterate the importance of timing as a performance metric,[222] and have a strong interest in evaluating in the follow-on CPCN proceedings a mechanism to incentivize timely completion of Company-owned projects, in accordance with the timing anticipated in the modeling and bidding processes. For example, one possibility would be to commence the LEC

[221] Public Service's Response Comments, p. 82.
[222] *See* Decision No. C23-0672-I, ¶ 6.

calculations on the as-bid ISD of the Company-owned project. Thus, if the as-bid ISD of a project was May of 2026 but the project experienced delays and did not commence operations until October 2026, this six-month delay would decrease the project's achieved LEC as compared to the as-bid baseline LEC. While we do not adopt this structure as part of this Decision, we intend to evaluate in the follow on CPCN proceedings how best to align the Company's incentives regarding the completion of generation projects.

194. Regarding curtailments, we likewise intend to continue evaluating in the follow on CPCN proceedings how exactly the operational PIM should account for curtailments. To be clear, we do not intend for the operational PIM to somehow shift the risk of curtailments on to the Company. The issue of appropriately disincentivizing curtailments across the entire electrical system is better addressed elsewhere, including possibly through the emissions reduction PIM that the Phase I Decision contemplates. In this way, we largely agree with the Company's position that the operational PIM should not seek to manage curtailments.[223] Nevertheless, there are unresolved details regarding how to make the operational PIM appropriately indifferent to curtailments, and we intend to address these details in the follow on CPCN proceedings.

### c. Extraordinary Circumstances

195. Finally, as to both the cost to construct PIM and the operational PIM, the Commission finds merit in Public Service's argument that the Company should be able to petition the Commission for relief in the event of extraordinary circumstances. In other words, Public Service can seek relief from the Commission for any amounts assessed to the Company under either the cost to construct PIM or the operational PIM, with the Company bearing the burden of establishing the existence of extraordinary circumstances and the impact of any such

[223] Response to Decision No. C23-0672-I, pp. 12-13.

circumstances on unit construction.[224] We clarify that the starting point for the definition of "extraordinary circumstances" could be similar to the definition of "force majeure" in the Model PPA for Wind and Solar.[225] That said, in the proceeding in which the Company attempts to establish the existence of extraordinary circumstances, the parties—including the Company—may advocate for modifications to the definition of "extraordinary circumstances" as appropriate, recognizing that Company-owned projects may not have identical extraordinary issues to the Model PPA.

#### d. Other proposed PIMs

196. We decline to implement Staff's proposed PIM in this Proceeding given our adoption of a cost to construct PIM and operational PIM. Nevertheless, we are intrigued about the possibilities offered by Staff's PIM. As Staff notes, under its PIM, cost recovery increases in direct proportion to the amount of renewable energy the assets produce while also tying cost recovery to Public Service's Phase II bids. Likewise, the PIM would account for both capital construction costs and performance of the assets.[226] The Commission sees Staff's PIM as a potential avenue to engage in performance based regulation (PBR) on a more fundamental level as opposed to simply overlaying PIMs on top of the standard cost of service ratemaking, providing a potential opportunity to realign utility incentives to benefit ratepayers.

197. Many of Public Service's arguments against Staff's PIM are focused on why it should not be applied to the Company-owned projects arising from this Proceeding. Arguments that Staff's PIM "moves the goalposts" after submission of Phase II bids and that Staff's PIM has many unresolved details might be legitimate as to this Proceeding but are far less

[224] Response to Decision No. C23-0672-I, p. 15.
[225] Hearing Exhibit 101, Attachment AKJ-3 (Volume 3.2), pp. 142-43.
[226] Staff's Response to Decision No. C23-0672-I, pp. 14-15.

persuasive regarding future implementation of Staff's PIM. Given the Commission's longstanding interest in PBR and the fact that the Commission has already approved a similar approach for one of Black Hills' wind projects,[227] the Company's claims that Staff's PIM would essentially deregulate generation in Colorado seem exaggerated.

198. The Commission intends to evaluate in the 2024 JTS whether Staff's PIM can be applied to the Company-owned projects arising from that proceeding. As such, we request that Public Service confer with Staff on its proposed PIM[228] prior to the 2024 JTS in an attempt to reach consensus. Regardless of the outcome of the conferral, we invite the parties in the 2024 JTS to raise this issue for our continued consideration.

199. As for the remaining proposed PIMs, including those that Boulder, COSSA/SEIA, and Conservation Coalition put forth in their comments, we decline to adopt these concepts in this Proceeding. Although the expedited nature of this Phase II process did not allow for the development of a robust record for these proposals, we invite the parties to consider bringing these proposals forward in the PIM stakeholder process that the Phase I Decision contemplates and through future proceedings.

### H. The Sand Creek Massacre National Historic Site and Bid 1029

200. Bid 1029 is included in the Preferred Portfolio, the UPP, and the Alternative Portfolio and is a 500 MW Company-owned wind project with an in-service date of 2026. Although the Commission does not know the precise location of Bid 1029, it appears to be close to and possibly adversely impacts, the Sand Creek Massacre National Historic Site view shed.

[227] Staff recounts that Black Hills recovers the cost of the Peak View wind farm exclusively through the ECA and RESA for the first ten years of commercial operation. (Staff's Response to Decision No. C23-0672-I, p. 9).

[228] This conferral should include further evaluation of whether Staff's PIM could be modified to apply to LCC-based projects instead of only LEC-based projects.

201. On October 25, 2023, elder and tribal administrator Mr. William Walksalong of the Northern Cheyenne Nation spoke at the Commissioner's weekly business meeting. Through comments, tribal representatives requested that the Commission protect from energy development the viewshed of the Sand Creek Massacre National Historic Site given its sacred importance to several tribal nations. In addition, Mr. Walksalong asked that the Commission ensure that energy development not disturb any human remains or cultural artifacts from the area around the Sand Creek Massacre National Historic Site. Mr. Walksalong noted that the massacre spilled well-beyond the boundaries of the Sand Creek Massacre National Historic Site that Congress has designated. Consequently, he urged the Commission to require utilities and developers to consult tribal representatives as to how to proceed should remains or artifacts be discovered in the course of construction.

202. In its comments, Staff recommends the Commission not approve Bid 1029 as part of this Proceeding. Staff asserts that a preliminary viewshed analysis indicates that wind turbines from Bid 1029 might impact the Sand Creek Massacre National Historic Site's viewshed. Staff also ran its own modeling runs that forced the model to exclude Bid 1029 and suggests that the Commission could approve a 200 MW solar plant (Bid 375) or a 603 MW wind plant (Bid 1024) in place of Bid 1029.[229]

203. CEO also recognizes concerns regarding Bid 1029 but does not suggest that the Commission exclude it from the approved CEP. Rather, CEO recommends the Commission direct the Company to include additional information in subsequent CPCNs, including discussions between the Company and Tribal governments regarding the proposed projects, the status of those

[229] Staff's Comments, p. 58-59.

discussions, and any outcomes or results of such discussions.[230] CEO argues that approach will allow the Commission to take action in the instant proceeding consistent with the presentation by the Northern Cheyenne Nation and also rely on the existing CPCN process to consider alternatives and proposed impacts when making a determination on specific resource proposals.[231]

204. In its Response Comments, Public Service argues that Bid 1029 has "strong economics" and was included in almost all portfolios. Thus, the Company maintains that it would be premature to set this bid aside. Public Service does, however, acknowledge Staff's concerns and states that the identified impacts are important to work through and address. Indeed, the Company states that it is already engaged with these issues. Ultimately, Public Service asks that the Commission allow Bid 1029 to move forward and states that the Company would then provide an update on efforts to mitigate the impacts of concern in the follow on CPCN proceeding.[232]

205. The Commission agrees with the positions of Public Service and CEO and rejects Staff's proposal to exclude Bid 1029 from the approved CEP. We emphasize, however, that allowing the Company to include Bid 1029 in the Alternative Portfolio is in no way an approval of the project, which must necessarily be vetted through continued stakeholder and community considerations. In this vein, we adopt Public Service's suggestion to approve a backup bid for Bid 1029 so that the Company can pivot to a different project if stakeholder processes, including the Company's further discussions with the Northern Cheyenne Nation, do not resolve concerns. In addition, we adopt CEO's recommendation and direct Public Service to include additional information in subsequent CPCN proceedings, including discussions between the Company and Tribal governments.

[230] CEO's Comments, pp. 26.
[231] CEO's Comments, pp. 26.
[232] Public Service's Response Comments, pp. 23-24.

206. Resolution of this issue will require collaboration of the interested stakeholders, and we are encouraged by indications that Public Service is already engaging with the Northern Cheyenne Nation regarding Bid 1029. In this instance, Public Service needs to take the lead and work with interested stakeholders, including the Northern Cheyenne Nation, to address potential impacts to the Sand Creek Massacre National Historic Site.

207. As to the precise backup for Bid 1029, in its Response Comments Public Service recommends that the Commission approve Bid 1018. However, Bid 1018 is unavailable as a backup because it is located on the MVLE, which the Alternative Portfolio does not include. Ultimately, we permit the Company discretion to select an appropriate backup for Bid 1029 pursuant to the approved backup selection process set forth in this Decision. We note, however, that Bid 1016 (a 554 MW Company-owned wind bid) appears to be a good candidate.

**I. Hayden Biomass**

208. Bid 1031 is a 19 MW Company-owned biomass project that Public Service proposes as a Section 123 resource.[233] The proposed project is located near Hayden, Colorado to support workforce transition as part of the planned retirement of the Hayden coal units.[234]

209. Public Service states that it would employ 26 full-time employees, thus reducing workforce transition costs associated with the early retirement of the Hayden coal plants. Public Service further asserts that the project, which is anticipated to use primarily forest waste from fire prevention activities and debris from pine beetle outbreaks, is carbon neutral and would reduce air emissions, including particulate matter, carbon monoxide, volatile organics, and

[233] Public Service also states that it "complies with the spirit of" the portfolio development framework for HB 21-1324. (120-Day Report, p. 52).

[234] In its Response Comments, Public Service intentionally presents the bid name with the bid ID as public information.

nitrogen oxides.[235] In comparing the Preferred Portfolio with the Hayden biomass project to a reoptimized portfolio without the project, the portfolio excluding biomass adds 19 MW gas and 200 MW solar and is $257 million less in PVRR.[236]

### 1. Party Comments

210. The Labor Interests argue that the Hayden biomass project should belong in any Commission-approved portfolio, listing its benefits as including 26 well-paid jobs and a high total BVEM rating for its construction phase. The Labor Interests add that the Hayden biomass unit represents an innovative technology under both Section 123 and HB 21-1324, noting that wind and solar projects have often dominated discussions about innovation despite patterns of low-paying jobs post-construction.[237]

211. CEO supports the inclusion of the Hayden biomass plant in the Commission-approved CEP primarily because of its just transition benefits. CEO acknowledges, however, that Public Service "does not provide information on the salaries or the estimated tax benefits" and requests that the Company provide more details about the public benefits of the project "so the Commission has a full record on which to make its Phase II decision."[238] CEO also notes the relatively high cost of the biomass plant, concluding that the Hayden biomass project increases the PVRR of the Preferred Portfolio by $257 million.[239] CEO recommends that if the Commission does not approve the Hayden Biomass project here, the Commission direct the Company to evaluate the project in future ERPs for additional consideration.[240]

[235] 120-Day Report, p. 40.
[236] 120-Day Report, p. 138.
[237] Labor Interests' Comments, pp. 11-14.
[238] CEO's Comments, p. 23.
[239] CEO's Comments, p. 22.
[240] CEO's Comments, pp. 17.

212. OJT endorses CEO's Comments as to the just transition issues, including the evaluation of the Hayden biomass project.[241] OJT opines that the biomass project would employ a third of the coal plant's current workforce, generate a "significant, though yet-unspecified, amount of property tax revenues," and create long-term supply chain jobs in the region for timber harvesting and processing.[242] However, OJT also requests that Public Service provide more specific information on the expected local economic and employment benefits, including information about jobs retained or created and property and other tax revenues generated.[243]

213. Public comments from entities such as the Moffat County Board of County Commissioners, the Routt County Board of County Commissioners, the City of Craig, Northwest Colorado Development Council, Colorado State Senator Dylan Roberts, and the Town Council and Mayor of Hayden also expressed support for the Hayden biomass project, citing the risk that not replacing the coal plant will lead to cascading effects in the form of losing high-paying jobs and reducing funding for important government services.

214. In contrast, certain other parties recommend the Commission reject the Hayden biomass project and potentially reconsider it in an alternative proceeding, mostly pointing to the upcoming 2024 JTS. For example, CEC asserts that the Company has not established that the project is the best solution for the Hayden community, nor that it is worth the additional expense or necessary for emissions reductions.[244]

215. Staff argues that the Hayden biomass project is very high cost and is overall uneconomic, with unclear information about jobs benefits and tax revenue replacement.

[241] OJT's Comments, p. 3.
[242] OJT's Comments, p. 6.
[243] *See* OJT's Comments, pp. 3, 6.
[244] CEC's Comments, pp. 13-14.

Staff asserts that the Hayden biomass plant is not designed as a closed-loop facility and thus will not enjoy access to a full production tax credit, meaning that the cost of the biomass unit presented in the 120-Day Report is artificially low. Staff states that it conferred with the Company, which agreed with this critique.[245] Staff also raises concerns that the Hayden biomass project is not sufficiently novel or scalable to be a Section 123 project.[246] Staff suggests that the Commission consider alternatives to the biomass facility in future proceedings.[247]

216. Similar to Staff, WRA raises concerns not only about cost, but also about environmental claims made about the Hayden biomass project. Referencing recent studies, WRA asserts that emissions from the harvesting stage strongly erode any potential emissions benefit, and inefficiencies mean electricity generation with woody biomass can be more carbon-intensive per MWh than coal-generated electricity.[248] WRA argues that Public Service's assertions about the Hayden biomass project being greenhouse gas neutral are incorrect as a matter of practice—biomass electricity generation produces carbon dioxide—and also that the Company has failed to provide information demonstrating that emissions released from combustion are less than would have been emitted without being converted to electrification, pursuant to § 40-2-124(1)(a)(IV).[249] Moreover, WRA states that the 120-Day Report provides insufficient information about planned forest management practices and leaves open the idea that other fuel would be used besides that from fire prevention and pine beetle kill.[250]

217. Like Staff and WRA, Conservation Coalition raises concerns that greenhouse gas emissions from the biomass project will exceed the Company's estimates. Conservation Coalition

[245] Staff's Comments, p. 53.
[246] Staff's Comments, pp. 51-52.
[247] Staff's Comments, p. 51.
[248] WRA's Comments, pp. 9-10.
[249] WRA's Comments, p. 11.
[250] WRA's Comments, p. 12.

argues that the Commission can consider additional measures for the Hayden community in the 2024 JTS, noting that the last unit at Hayden is not scheduled to retire until 2028.[251] Additionally, public comments from entities like 350 Colorado similarly urge the Commission to find other ways to meet just transition needs due to environmental risks associate with the proposed biomass project, including air pollutant emissions and the potential that salvage logging and deforestation activities may be required to meet fuel needs.

218. In its Response Comments, Public Service reiterates that the Hayden biomass project contributes to three policy objectives: developing clean firm dispatchable capacity with wildfire mitigation benefits, making progress towards emissions reduction goals, and providing just transition benefits. The Company states that not providing new workforce opportunities for communities affected by energy transition is "not a viable path."[252] However, Public Service also recognizes that questions about cost and tax credit eligibility are legitimate, and therefore proposes alternative procedural pathways, including conditional approval of the project with additional analysis in a follow-on CPCN filing or consideration within the Hayden JTP filing.[253]

### 2. Findings and Conclusions

219. In its Phase I Decision, the Commission approved provisions of the Phase I Settlement specifying that Public Service will make follow-on JTP filings for each area with an affected coal plant after the Phase II final decision.[254] For purposes of Phase II modeling, JTP costs will include costs associated with workforce transition and community assistance.

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[251] Conservation Coalition's Comments, pp. 15-16.
[252] Public Service's Response Comments, p. 19.
[253] Public Service's Response Comments, pp. 19-20.
[254] Phase I Settlement, ¶ 109.

220. Regarding the Hayden 1 and Hayden 2 coal plants, the estimated costs of the community assistance is the projected lost property tax revenues for six years following retirement of the respective plant, but these costs may be offset by other investments in the community.[255]

221. The Commission takes seriously its role in supporting a just transition for workers and communities that are impacted by the closure of coal units as part of creating a cleaner energy system. The labors and skills of these communities helped propel Colorado's economy and the reliable electricity we have enjoyed for generations. We have a commitment to do what we can to ensure these communities are not left behind in the energy transition, and this might go beyond even the six-year commitment that was contemplated in the Phase I Settlement. Regarding the closures of Hayden 1 and Hayden 2, we recognize the transmission resources that will be made available in the near future as well as the potential expansion of these transmission resources into the western market. In short, the Commission is hopeful that there will be opportunities for resource development that benefit both local communities and ratepayers in general.

222. Nevertheless, we decline to approve the Hayden biomass project in this Proceeding. We do not have in front of us a complete proposal that allows us to determine whether the project is in the public interest. For example, we are concerned by Staff's assertion that the Company will not qualify for closed-loop biomass tax credits, which leaves the actual cost of the project uncertain, and we are troubled by the potential environmental impacts of the plant that WRA and others raise. Moreover, even CEO and OJT seem to acknowledge that the current proposal lacks important information regarding workforce transition and community benefits. The Hayden biomass project would cost ratepayers approximately $257 million in PVRR before upward

[255] Phase I Settlement, p. 19.

adjustments due to tax credit miscalculations, and this is for a relatively small 19 MW project that would replace what has been hundreds of MW of capacity from the Hayden coal plants.[256]

223. While we decline to approve the Hayden biomass project here, in the event Public Service develops clearer answers to the questions raised by parties about the environmental, financial, workforce, and community benefits of the plant, we encourage the Company to bring this or another just transition proposal forward for further consideration as part of the 2024 JTS. The 2024 JTS proceeding[257]—as opposed to the Hayden JTP or a standalone CPCN—will allow the Commission and stakeholder to evaluate the costs and benefits of the biomass project, if rebid, more holistically with other alternatives, including potentially other bids from IPPs that could provide similar tax, employment, and other benefits to the local community. We conclude that reconsidering this or other similar projects in a full competitive solicitation will be the best way to maximize benefits to both the Hayden community and to ratepayers more generally.

224. To effectuate this, Public Service shall confer with relevant stakeholders and determine whether it makes sense to bring forward the Hayden JTP within 120 days of the Phase II decision, consistent with approved provisions of the Phase I Settlement, or to postpone that filing. In conferral with settling parties, and particularly those affected by the potential Hayden JTP filing, since the Hayden Biomass project or other beneficial projects could potentially be reevaluated in the 2024 JTS, we permit flexibility on whether the Hayden JTP should be filed 120 days following the Phase II decision or at a later date.

[256] *See* CEO's Comments, p. 22 (comparing Preferred Portfolio with Hayden biomass to the Preferred Portfolio without Hayden biomass).

[257] The Commission emphasizes that the primary focus of the 2024 JTS is the replacement of Unit 3 and the corresponding impacts to the Pueblo community. Nevertheless, as an interim ERP the 2024 JTS also provides an opportunity to evaluate more holistically the various resource opportunities in the Hayden community.

### J. Backup Bids

225. In the 120-Day Report, the Company proposes three tools to mitigate the risks associated with potential project failure: extensive due diligence, right of first offer (ROFO), and backup bids. Public Service further notes that the 2024 JTS allows for a more rapid opportunity to course correct than the standard four-year ERP cycle typically provides.[258] Regarding the backup bids, Public Service states that these bids are intended to be pre-approved by the Commission as a set of projects to be "next in line" to replace a project in the approved portfolio if it fails.

#### 1. Party Comments

226. Staff is generally supportive of the establishment of a pool of back-up resources. However, Staff is concerned that approving a backup pool of bids that includes both Company-owned and PPA bids may create perverse incentives for the Company in negotiating projects. For instance, Staff questions whether the Company's PPA negotiations with an IPP would be impacted if the IPP project would be replaced with a Company-owned project.[259]

227. Staff recommends that the Commission consider a back-up bid replacement process in which additional process is required for Company-owned backup bids. If a failed project is being replaced by a PPA project, the Company should notify the Commission of such a failure and the steps it intends to take to address the failure, but the Company need not seek Commission approval prior to commencing negotiations. If a failed project is being replaced by a Company-owned project, however, the Company would be required to do the following: (a) notify the Commission and provide additional evidence and detail regarding the steps taken to attempt to

[258] 120-Day Report, pp. 44-46.
[259] Staff's Comments, p. 66.

remediate the failed project; (b) retain the burden to prove that the Company-owned project was the prudent replacement; and (c) provide robust alternatives analysis as part of the follow-on CPCN proceeding. Regarding the available pool of backup bids, Staff recommends that any project included in the Company's inverse Preferred Portfolio that is not ultimately approved in this Proceeding should be eligible for inclusion in the back-up pool.[260]

228. Similar to Staff, CIEA approves of the backup bid concept and recommends that the Commission approve the backup bid projects as contingency projects. However, CIEA asserts that it will be important for the Commission to clarify the back-up bid process and list clear criteria to avoid controversy in the implementation of Phase II.[261]

229. COSSA/SEIA also raises concerns with perverse incentives that could arise when an IPP project fails but focuses its concern on the Company's ROFO. The ROFO is a provision in the model PPA that allows the Company to step into a failed IPP project and take over development. COSSA/SEIA recommends that the Commission require the Company to first use its identified list of backup bids before deploying the ROFO, as the latter guarantees that the Company's ownership share will grow after a project fails. COSSA/SEIA argues that allowing for ROFO to be used prior to backup bids could incentivize the Company to slow-walk PPA negotiations, placing IPP projects in peril, with the knowledge that the Company can simply offer to buy the developer out if or when the project goes south.[262]

230. In its Response Comments, the Company agrees that some of the intervenor recommendations have merit but argues for the importance of maintaining price integrity and

[260] Staff's Comments, p. 66.
[261] CIEA's Comments, pp. 24-25.
[262] COSSA/SEIA's Comments, pp. 18-20.

allowing for flexibility to move to a backup bid for timely replacement.[263] The Company argues that, to the extent practicable, the Company will try to select "like for like" backup bids both in terms of technology and ownership. More specifically, Public Service argues that it should be able to move forward with an IPP backup bid after a simple notice provided to the Commission and when the backup bid is Company-owned, the Company should only be subject to a "limited-scope" CPCN process similar to any other Company-owned project in an approved resource plan.[264]

231. Public Service argues against adopting an approach set forth by Staff and others in which the Company would be required to undergo more process when it replaces and IPP project with a Company-owned project. The Company acknowledges the "academic" concerns about perverse incentives but argues that its commitment to strive for "like for like" replacements and the Company's conduct in this Proceeding should comfort the Commission.[265] Public Service further argues that a limited scope CPCN is appropriate because Company-owned replacement projects would need to move quickly in order to meet resource needs.

232. Public Service also argues the presumption of prudence under Rule 3617(d) should apply to all backup bids as they move forward, providing regulatory certainty for these projects.

233. Finally, in its Response Comments, Public Service notes two resource modifications in the UPP: (1) replacing a Company-owned solar plus storage project (Bid 0476) with an IPP solar plus storage project (Bid 0303), and (2) replacing a Company-owned wind project (Bid 0045) with a different Company-owned wind project (Bid 1024). The Company also requests that the Commission approve a specific backup for Bid 0044. Bid 0044 is an IPP wind

[263] Public Service's Response Comments, pp. 39-40.
[264] Public Service's Response Comments, p. 42.
[265] As an example of the Company's conduct, Public Service notes that in the UPP the Company proposes to replace a Company-owned bid (Bid 0467) with an IPP bid (Bid 0303). (Public Service's Response Comments, p. 42).

bid that might not be able to move forward at its as-bid price. The Company requests that the Commission approve Bid 0254 as its backup. Bid 0254 is also an IPP wind project.[266]

234. Because the resource modifications in the UPP impact the backup bid portfolio, Public Service provides an updated portfolio of backup bids set forth in Table 3 of its Response Comments.[267]

### 2. Findings and Conclusions

235. At the outset, the Commission expressly approves the updated list of backup bids set forth in Table 3 of the Company's Response Comments. Recognizing that the backup bids in Table 3 were compiled in anticipation of the UPP and not the Alternative Portfolio, however, we clarify that the Company may use its discretion to adjust the portfolio of backup bids as necessary given the authorizations we have attached to the Alternative Portfolio. For instance, consistent with Staff's recommendation to include projects from the inverse Preferred Portfolio, it would be reasonable to include as a backup bid any bid within the UPP that is not in the Alternative Portfolio.

236. In addition, we agree with the Company's position and confirm that the presumption of prudence set forth in Rule 3617(d) applies to any backup bid that moves forward in accordance with the Commission's approved process for selecting backup bids.

237. Regarding the selection of backup bids, the Commission finds merit in the concerns raised by Staff, CIEA, and COSSA/SEIA that there should be more process in place for when Public Service selects a Company-owned backup bid or when the Company uses its ROFO to buy-out a failing IPP bid. We find persuasive the arguments regarding perverse incentives and worry that without additional process, the selection of a Company-owned backup bid or the

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[266] *See* Public Service's Response Comments, p. 6.
[267] Public Service's Response Comments, p. 27.

exercise of the Company's ROFO could give rise to the appearance of bias. While the Commission acknowledges the benefits of allowing the Company discretion to quickly pivot to a backup bid, these benefits must be balanced with guardrails that protect customers, enhance fairness amongst bidders, and increase transparency. Conversely, the Commission disagrees with suggestions from CIEA that the Commission should establish clear criteria for the selection of backup bids or mandate like-for-like replacements. Apart from concerns regarding the selection of a Company-owned bid instead of an IPP project, we believe that Public Service should have the flexibility to use its discretion to select the most appropriate backup bid.

238. Accordingly, we generally adopt Staff's suggested approach in which—among other things—Public Service retains the burden of proving that any Company-owned backup project was the prudent replacement and would need to provide a robust alternatives analysis as part of the follow-on CPCN proceeding.[268] The additional protections set forth in Staff's approach also apply when the Company exercises its ROFO and when the Company replaces a Company-owned project with a Company-owned backup. That said, we emphasize that the additional process set forth in Staff's proposal must move quickly, especially in instances in which the replacement is like for like.

239. Finally, we clarify that the backup bid selection process set forth above does not apply to the two replacement projects the Company proposed as part of the UPP. Specifically, the Company may replace Bid 0476 with Bid 0303 and may replace Bid 0045 with Bid 1024. The Company already explains the need for replacement and the economics of alternative backup bids in its Response Comments. Moreover, the concerns that the Company would have perverse incentives during PPA negotiations do not apply at this point in the process. For the same reasons,

[268] *See* Staff's Comments, p. 66.

we approve Bid 0254 as the backup bid for Bid 0044 if Bid 0044 cannot move forward. Acknowledging that the Company's Response Comments presumed the selection of the UPP, as opposed to the Alternative Portfolio, we clarify that the Company has the flexibility to make the necessary resource modifications consistent with the Company's Response Comments.

**K. Section 123 Resources**

240. In the 120-Day Report, Public Service states five bids qualified as Section 123 Resources pursuant to the criteria established in the Phase I Decision.[269] In addition to the Hayden biomass project, Bids 0011, 0106, 0269, and 0552 were considered as Section 123 Resources. Other than the Hayden biomass, only Bid 0011 was sometimes selected in the Phase II portfolios.[270] While Public Service included the Hayden biomass project in its Preferred Portfolio, the Company rejected the other Section 123 resources for various reasons, including cost, project risk, and location. Regarding Bid 0106 (a hydrogen fuel cell project) and Bid 0269 (a long-duration storage project), the Company states that there could be long term benefits if these projects are successful. Public Service states that the Company would be interested in moving forward with these projects if the Commission were to approve them *in addition to* the other projects in the Preferred Portfolio.[271]

241. CEO supports the Commission approving Bid 0106 (the hydrogen fuel cell project). CEO argues that pursuing this project as a firm resource would help the state continue its development of hydrogen as a pathway to decarbonization. While CEO acknowledges the project involves certain risks, CEO argues that the potential benefits outweigh these risks, noting that the

[269] Public Service notes that one additional project claimed Section 123 but did not meet the Phase I Decision's criteria.
[270] 120-Day Report, p. 139.
[271] 120-Day Report, pp. 150-51.

State intends to continue pursuing the development of hydrogen. Alternatively, if the Commission does not believe it is the right time to approve the project, CEO recommends that the Commission "direct Public Service to pursue a similar project in either the Just Transition Plan or through its next ERP in 2026."[272]

242. In its Response Comments, Public Service maintains that it does not recommend approval of the project as part of this Phase II ERP. However, the Company states that it appreciates and shares CEO's interest in pursuing the hydrogen fuel cell project and that Public Service is interested in exploring the viability of the project. Public Service goes on to state that it sees opportunities to pursue Bid 0106 or other hydrogen projects as part of proceedings conducted pursuant to HB 23-1281, the upcoming 2024 JTS, or through a separate filing.[273]

243. Pursuant to § 40-2-123(1)(a), C.R.S., the Commission shall:

> give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, insulation from fuel price increases, and environmental protection, including risk mitigation in areas of high wildfire risk as designated by the state forest service.

244. As required, the Commission has fully considered Section 123 Resources. This consideration began in Phase I when the Commission approved a modeling approach for Section 123 Resources and adopted guidelines proposed by Public Service to define these resources, emphasizing that they must be new, innovative, not commercialized, and could not include standalone wind, solar, or lithium-ion storage.[274] This framework enabled the efficient presentation of Section 123 Resources in the 120-Day Report, which in turn allowed the

[272] CEO's Comments, pp. 18-20.
[273] Public Service's Response Comments, pp. 110-11.
[274] Phase I Decision, ¶ 501.

Commission and stakeholders to evaluate the various risks and potential benefits of the Section 123 Resources.

245. We have considered the beneficial attributes of all of the Section 123 Resources, including Bid 0106 which CEO supports. We further note that the Alternative Portfolio includes Bid 0011 which, while proposed as a Section 123 Resource, was included based on economic modeling. As to the question of whether additional Section 123 Resources should be pursued at this time, however, we agree with Public Service's position set forth above in its Response Comments. Given uncertainty ranging from tax credits to the implementation of HB 23-1281, it would be premature to approve additional projects here, including Bid 0106. Should hydrogen projects be included as bids within the 2024 JTS, they can be more appropriately considered there. Accordingly, no further Section 123 Resources are approved here, and we look forward to consideration of innovative technologies in the 2024 JTS.

**L. Prospective New Load**

246. In its 120-Day Report, Public Service states that large loads, such as the demand and energy requirements of new data centers, are developing at a faster pace than historic trends. The Company thus requests that the Commission approve a "Prospective New Load Preferred Plan" (PNL) portfolio to accommodate potential new load of 300 MW beginning in January 2026. Public Service states that at least some of this 300 MW new load would be better described as "more likely" than "possible." The Company recommends the Commission allow it to use the backup bid pool to serve this load if needed. Public Service specifically puts forth four additional bids that would be included in the PNL portfolio: two storage projects, as solar project, and a 219 MW gas project.[275]

[275] 120-Day Report, pp. 55-57.

247. Several parties, including CEO, Conservation Coalition, Interwest, Staff, and WRA raise concerns about the PNL portfolio, particularly its inclusion of 219 MW of new gas generation. CEO and Staff suggest that the new load is speculative and could fail to materialize, and with Conservation Coalition and WRA, recommend that new load be addressed as part of the load forecast in the 2024 JTS.[276] Staff asserts that two large wholesale loads have announced the intention to leave the Company's system but remain in the Company's load forecast, which cuts against the arguments that additional generation resources will be necessary. Likewise, Staff critiques the Company's demand response sensitivity analysis, arguing that aggressive demand side solutions would mitigate concerns regarding new load.[277] CEO adds that if the Commission does approve the PNL portfolio, it should ensure ratepayer protections if the new load fails to emerge. For example, CEO suggests that if new load does not emerge, shareholders should be responsible for the cost of additional new gas generation instead of ratepayers.[278]

248. In its Response Comments, the Company maintains that that the PNL portfolio has value in this Proceeding and as a general resource planning matter in the current environment. Public Service acknowledges intervenors' comments that new load is speculative but states that it has more information than intervenors and reiterates the challenge associated with new, large loads developing at a faster pace than before. Public Service agrees, however, that should additional resources not be approved for procurement here, it is reasonable to revisit the issue in the 2024 JTS.[279]

[276] Staff's Comments, pp. 53-54; CEO's Comments, pp. 15-16; WRA's Comments, pp. 19-20; Conservation Coalition's Comments, p. 14.
[277] Staff's Comments, pp. 53-54.
[278] CEO's Comments, p. 16.
[279] Public Service's Response Comments, p. 106.

249. We take the risk that new load is increasing seriously,[280] but we decline to approve the PNL portfolio. We agree with Staff's assertion that based on what is currently publicly known, these load additions are speculative and could be offset by future load departures and more effective efforts around demand response. Moreover, given that the new load is speculative but would directly result in adding a new gas resource, it deserves both the full vetting of a Phase I process, through which such questions of appropriate load forecasts and sensitivities are traditionally considered, and consideration as to the impact of new large loads that might seek economic development rates on state emissions targets.

**M. Clean Energy Plan Rider (CEPR)**

250. Section 40-2-125.5(5), C.R.S. authorizes Public Service to initiate a CEPR, capped at a maximum rate of 1.5 percent of customers' total electric bill, to collect new revenues to fund the approved, additional clean energy plan activities that are undertaken to meet the clean energy target applicable to the Company. However, the statute also prescribes limitations on what the CEPR can fund.

251. In Phase I, the Commission rejected the complex, counterfactual modeling proposal put forward by Public Service in support of the approval and prospective implementation of its CEPR. The Commission further declined to move forward with Public Service's presumption that the Company could apply RESA funding to offset CEP costs, even as the Commission approved certain related provisions of the Phase I Settlement that relate to reporting and treatment of over- and under-collections. Instead, the Commission directed Public Service to file significantly more detail on anticipated cost recovery mechanisms in the 120-Day Report and to file an

[280] To address this risk, we encourage Public Service to work to ensure that it has additional firm dispatchable resources as close to construction ready as reasonably possible.

application in a separate future proceeding presenting its methodology for defining and assigning costs related to additional clean energy activities as between the CEPR and the RESA, no later than one year in advance of beginning to recover costs attributable to the CEPR.

### 1. Public Service's New CEPR Proposals and Party Comments

252. In its 120-Day Report, Public Service completely revises its cost recovery methodology as compared to the proposals the Company presented in Phase I of this Proceeding. For instance, the Company compared its Preferred Portfolio to the reference case and identified the following incremental actions and investments: acquisition of clean energy resources, the Brush Coal Plant gas conversion, reduction of Pueblo Unit 3 operations, gas storage, transmission, and community assistance and workforce transition plans. Out of these, Public Service states that clean energy resources, Brush Coal Plant conversion costs from 2025-2030,[281] and community assistance and workforce transition plans should be considered clean energy plan activities that are eligible for CEPR recovery (noting that community assistance and workforce transition costs are statutorily also eligible to be recovered through other riders). Public Service explains that, pursuant to § 40-2-125.5(5)(b)(III), the Company will exclude transmission, fuel costs for Pueblo unit 3 operations, and gas storage, and proposes they be collected from other cost recovery mechanisms, such as the ECA, the Transmission Cost Adjustment, and base rates.[282]

253. To attribute the costs of clean energy plan activities to the CEPR, Public Services proposes to sort resources into energy or capacity and then to stack them from lowest to highest based on accredited capacity and levelized cost of energy or capacity calculated using Encompass, the model used for bid evaluation and selection.[283] This approach results in three solar and storage

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[281] The Brush Coal Plant conversion costs are also being considered within Proceeding No. 22A-0563E.
[282] 120-Day Report, pp. 168-69.
[283] 120-Day Report, p. 169.

resources being identified as attributable to the CEP in the "energy resource stack" and no resources being identified as attributable to the CEP in the "capacity resource stack." Public Service suggests refining this methodology and extending it to CEPR/RESA interactions through the post-Phase II application. Public Service also adds that the exact costs for community assistance and workforce transition will be evaluated in future JTP filings.[284]

254. Public Service requests that the Commission authorize it to file an advice letter to initiate the CEPR for collections purposes beginning either January 1, 2024, or January 1, 2025, depending on when the Phase II Decision is issued. Public Service forecasts that by starting collections at 1.4 percent in 2024, it would be over-collected by $6.3 million in 2030, and it would be under-collected by $19.3 million in 2030 if it began collections at 1.5 percent in 2025.[285]

255. UCA raises concerns about the Company's approach, including that the presentation of levelized energy costs for resource stacking does not match costs presented in appendices, and therefore the bids may be incorrectly sorted as to cost recovery mechanism. UCA further argues that the costs associated with the early retirement of Hayden 1, Hayden 2, Craig 2, and the entire costs of the Brush Coal Plant conversion should be considered CEP costs, and therefore the under-collections for the CEPR will be higher than Public Service anticipates.[286]

256. Public Service argues that UCA has not correctly applied updated modeling values and explains that only the conversion of the Brush Coal Plant from coal to gas would be considered an additional clean energy plan activity. With regard to the RESA, Public Service states that the methodology it used to distinguish between the ERP and the CEP will also be used to distinguish between clean energy resources and eligible energy resources. The Company reiterates that it

[284] 120-Day Report, pp. 170-72.
[285] 120-Day Report, pp. 172-73.
[286] UCA's Comments, pp. 27-28.

intends to file the application presenting its methodology for defining and assigning costs between the RESA and CEPR promptly after the final Phase II decision, consistent with the Phase I decision. Accordingly, Public Service reiterates its request that the Commission approve the establishment of the CEPR at the full 1.5 percent in its Phase II decision, with collections to begin as soon as possible upon filing of an advice letter.[287]

### 2. Findings and Conclusions

257. We conclude that further process is still required to determine whether the CEPR should be initiated at the full 1.5 percent as proposed by Public Service in its 120-Day Report. Nevertheless, we generally agree with, and approve, its categorization of actions and investments which should be considered additional clean energy plan activities, including those that may be recoverable through the CEPR,[288] as the Company's new proposals are clearer and will avoid the inappropriate levels of complexity that were present in the counterfactual Phase I proposal.[289] That said, given its late introduction, the balance of the Company's latest CEPR proposals has not been fully vetted by stakeholders and questions remain as to variations between data tables and appendices. Moreover, the application of this methodology for RESA/CEPR cost recovery is less clear than its applicability for ERP/CEP questions. Finally, the Commission has selected the Alternative Portfolio instead of the UPP, necessitating greater clarity on cost recovery (*e.g.*, whether the resource stack changes and results in different allocations between cost recovery mechanisms).

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[287] Public Service's Response Comments, pp. 98-100.

[288] To clarify, consistent with the discussion above, transmission investments as presented in the 120-Day Report are not considered additional clean energy plan activities.

[289] We note that while the Commission deferred the specifics of cost recovery for early retirement for Craig 2, Hayden 1, and Hayden 2, it approved the provisions of the Phase I Settlement that affirmed that they should be excluded from CEPR recovery (*i.e.*, they would be included within the reference case for modeling purposes), (Phase I Decision, ¶ 63; Phase I Settlement, ¶¶ 27-28). *See also* Proceeding No. 22A-0515E.

258. Given the timing of this Phase II Decision, pursuant to § 40-2-125.5(b)(II), C.R.S, the earliest the CEPR would be able to be placed into effect is January 1, 2025. Accordingly, we direct the Company, as part of its application regarding attribution of costs between the CEPR and RESA as still required by the Phase I Decision, to address the recovery of specific activities within the categories set forth above, based on the approved resource portfolio. The application should also address the appropriate level for the CEPR to be initiated on January 1, 2025.

**N. Best Value Employment Metrics**

259. The Phase I Settlement established a multistep process in the Phase II bid evaluation to ensure consideration of BVEM in accordance with § 40-2-129(1)(a), C.R.S. First, the RFP directed bidders to include quantitative information with bid packages that addressed the BVEM statutory requirements, including access to apprenticeships and industry-standard wages and benefits. Second, a bid incorporating a Project Labor Agreement (PLA) was deemed to meet threshold BVEM standards. Third, the Company agreed to screen bids based on BVEM and disqualify those that did not provide sufficient BVEM. Fourth, the Company would retain a labor economist to score the bids for advancement to computer modeling. The Phase I Settlement goes on to specify that the Company will provide a cumulative BVEM score for each portfolio in the 120-Day Report.[290] Finally, one of the required Phase II portfolios was a "high PLA portfolio."

260. In the 120-Day Report, Public Service confirms that it implemented this multi-step BVEM process during Phase II. The Leeds School of Business at the University of Colorado-Boulder was hired as a labor economist and provided scoring of 166 bids. The Company states that it disqualified bids with insufficient BVEM information. In addition, the

[290] Phase I Settlement, ¶ 69.

Company notes that Appendix K to the 120-Day Report contains the BVEM documentation that the bidders provided.[291]

261. The Labor Interests describe the challenging history of Colorado's efforts to account for the employment impacts of resource planning through the Phase II solicitation and modeling process. The Labor Interests describe the quantitative scoring provided by the labor economist as a positive evolution in the consideration of BVEM but remain concerned that BVEM was less emphasized after bids were advanced to modeling. Ultimately, however, the Labor Interests support the Preferred Portfolio including the Hayden biomass unit as having a strong BVEM score that matches or exceeds other modelled portfolios and offers an imperfect, but positive, middle ground. The Labor Interests note the positive relationship between utility ownership and BVEM due to Public Service's involvement in collective bargaining.[292] They further add that SB 23-292 is a recent and strong statement in support of robust and protective labor policies which will have a significant impact on all phases of energy generation in the future.[293]

262. Staff argues that the RFP informed the bidders of the categories and subcategories of information that would be used to develop the BVEM score, however, it did not specify the weighting of these categories and subcategories to the bidders. Staff is concerned that the approach incentivizes detail over quality. Staff suggests that the BVEM scoring methodology could use improved documentation as verifying the methodology is challenging due to lack of sufficient information. That said, Staff notes that it checked for consistency of BVEM scoring across

[291] 120-Day Report, pp. 159-60.
[292] Labor Interests' Comments, pp. 7-8.
[293] Labor Interests' Comments, pp. 8.

different bids and found it to be consistent and objective.[294] WRA likewise supports utilization of a BVEM scoring methodology in future ERPs.[295]

263. In its Response Comments, Public Service agrees with the Labor Interests that the BVEM scoring methodology in this ERP is an improvement and should be continued, with iterations. Public Service specifically supports using a similar BVEM scoring methodology in future ERPs, including the 2024 JTS.[296]

264. As noted earlier, the Commission has considered the employment of Colorado labor and its positive impacts on the long-term economic viability of Colorado communities throughout this ERP proceeding pursuant to § 40-2-129, C.R.S. These considerations began in Phase I of this Proceeding when the Commission approved the multistep process in the Phase II bid evaluation regarding BVEM and continued in Phase II in our review of the 120-Day Report, the relevant party comments, and the cumulative BVEM score for all portfolios. In addition to BVEM, the Commission must consider and balance many factors in its decision regarding the optimal resource portfolio, including emissions reductions, costs, and reliability. The consideration of these combined factors culminates in a Phase II decision.

265. The Alternative Portfolio has a slightly lower BVEM score (48 percent) than the UPP's BVEM score (52.7 percent). Nevertheless, we find that the positive attributes of the Alternative Portfolio, including cost, emissions reductions, reliability, and the ability to better address future technology developments and transmission concerns as detailed above, outweigh the lower BVEM score.

[294] Staff's Comments, p. 68.
[295] WRA's Comments, pp. 25-29.
[296] Public Service's Response Comments, pp. 106-07.

266. As Labor Interests set forth, the process of evolving a qualitative concept like BVEM into a meaningful component of bid evaluation has been a long and thoughtful process, with a significant amount of evolution demonstrated through the Phase I Settlement and Phase II. In such a sweeping and significant process as an ERP, even though moving incrementally can be frustrating, nuanced iterations are often the best course of action.

267. Moreover, the Alternative Portfolio includes slightly fewer resources and therefore will provide time for the application of BVEM to continue to evolve. This also means that resources that are deferred now could be brought into the future ERPs through an even more robust process, which is necessary to comply with additional statutory requirements in § 40-2-129, C.R.S.[297]

268. We also agree with Labor Interests that the thoughtful work performed by the labor economist in this Proceeding represents an enhancement of how BVEM can be incorporated into decision-making. However, Staff also raises valid points in that the methodology could be more clearly articulated for bidders. In this vein, we would be interested in seeing proposed changes to the model PPAs in the 2024 JTS aimed at clarifying standards for BVEM to ensure that IPPs and the Company are competing on a level playing field regarding BVEM. We encourage the collaboration of Labor Interests in this effort, such that work on the model PPAs will account for the role that the IRA can play in producing projects with high BVEM scores by incorporating factors such as the IRA's prevailing wage requirements. We also note that high BVEM scores generally track high utility ownership percentages and express our desire that IPPs that are interested in building projects in Colorado should improve their BVEM to ensure they stay competitive with Company-owned bids in this regard.

[297] These new requirements in § 40-2-129, C.R.S., are effective January 1, 2024.

### O. In Service Date Extensions

269. In connection with the delays in this Proceeding associated with Public Service's filing of the 120-Day Report, CIEA argues that the Commission should allow IPPs to have a corresponding extension of the ISDs of their projects. CIEA specifically proposes that all projects in the selected portfolio as well as backup bids with ISDs in 2026 and 2027 (spilling into 2028 by up to 75 days if necessary) should have a one-time election to extend the ISDs up to 75 days. CIEA argues that this will address the acute issues in the market and Public Service's delays in the Phase II process in a straightforward and transparent manner.[298] In addition, CIEA requests that backup bids should be granted an ISD extension equal to the number of days after the Phase II Decision when the backup bid gets approved to move to the selected portfolio.[299]

270. In its Response Comments, the Company supports CIEA's recommendations and agrees that all project developers should have the opportunity to extend the ISD of their approved projects and backup bids commensurate with the extended Phase II timeline. The Company further recommends the Commission acknowledge that delays in generation resource ISDs due to transmission-related delays, such as delays associated with interconnection, backfeed, and substation construction, shall be considered reasonable.[300]

271. Likewise, Public Service asserts that backup bids should be allowed an extension of their commercial operation date (COD) by the number of days after the Phase II Decision that the backup bid is approved to move to the selected portfolio. The Company supports this COD extension because selected backup bids will see a delay in their selection given their backup bid

[298] CIEA's Comments, pp. 41-42
[299] CIEA's Comments, pp. 41-42.
[300] Public Service's Response Comments, pp. 103-04.

status, and the COD extension increases the likelihood that the backup projects will come to fruition.[301]

272. In accordance with CIEA's recommendations, we authorize Public Service to extend ISDs upon application by IPPs by up to 75 days as well as any delays in transmission assets to which individual projects interconnect. No support should be required of the IPP for ISD delays of 75 days or fewer. Before granting an ISD extension greater than 75 days, the Company should be directed to obtain a thorough and credible explanation from the IPP detailing how delays related to completion of Public Service transmission projects prevented it from achieving its proposed ISD. We likewise adopt the ISD extension for backup bids that Public Service sets forth in its Response Comments.

**P. Repricing**

273. CIEA also requests that the Commission clarify that Public Service can allow IPPs to reprice their projects if delays in transmission project completion cause cost increases through no fault of the IPP. CIEA asserts that IPPs "cannot be expected to maintain as-bid pricing through material delays in transmission upgrade and interconnection processes."[302] CIEA similarly argues that backup bids are likely to be stale by the time Public Service calls upon such bids to move forward. Accordingly, CIEA argues that the Commission should allow an opportunity for limited repricing of backup bids to keep up with inflation.[303]

274. Public Service argues against the suggestion that backup bids should be provided a repricing opportunity, arguing that doing so could impugn the integrity of the process. However, the Company does support allowing price increases in the limited circumstance where a

[301] Public Service's Response Comments, pp. 40-41.
[302] CIEA's Comments, p. 22.
[303] CIEA's Comments, p. 25.

transmission cost estimate is different than the estimate provided as part of the RFP. Public Service states that this should be the only basis for repricing and should be equally applicable to any bid with which the Company moves forward.[304]

275. The Commission agrees with Public Service's position and denies CIEA's request to allow backup bids to reprice. The one exception is that repricing is allowed for backup bids in the case where the transmission costs provided in the RFP have changed, consistent with Public Service's proposal in its Response Comments.

### Q. 2024 Just Transition Solicitation

276. Given the various issues that have arisen in Phase II of this Proceeding, several intervenors argue that the Commission should issue various directives to Public Service to improve the ERP process. As discussed below, these proposed improvements cover topics including modeling, the ability of IPPs to negotiate the terms of Model PPAs during Phase II, and the appropriate amount of Company ownership.

#### 1. Modeling Improvements

277. Staff, CIEA, Interwest, Conservation Coalition, and WRA all put forth various proposals aimed at improving the modeling process of bids in the 2024 JTS. Relatedly, CEO suggests process improvements for the 2026 ERP. For example, CIEA's proposals include asking the Commission to reject the use of the things like the best-in-class modeling and the reliability rubric for use in the 2024 JTS.[305] CIEA also argues that the annuity method of modeling portfolios should be used going forward and that Public Service should be required to analyze the failure of

[304] Public Service's Response Comments, p. 41.
[305] CIEA's Comments, pp. 6-7, 29-31.

the model and possible solutions, including a process for returning to the Commission in the event of model failures.[306]

278. Interwest requests that the Commission require a full analysis of both the computer system used in this ERP as well as an estimate of what computer system would have been able to run the modeling software in the timeframe required under the ERP rules.[307] For future ERPs, Interwest argues that the curtailment projections must be more flexible and consider the likelihood that curtailments will be reduced over the long term.[308]

279. Conservation Coalition proposes numerous directives for the Commission to issue regarding the 2024 JTS. As an example of some of these proposals, Conservation Coalition argues that the Company should be required to provide the modeling input and output files to all parties and provide written explanation for all manual adjustments made to the modeling. Conservation Coalition also recommends that the Commission require the use of round-trip modeling, building all portfolios to the same minimum level of reliability, and running a scenario in which, the model replaces all 2-hour storage with 4-hour storage. Similarly, Conservation Coalition argues that Public Service should be required to conduct capacity accreditation studies and planning reserve studies in the same software tool and database to ensure consistency.[309]

280. WRA's proposals include things such as how generic prices should be used, requirements for the IE, and—more broadly—a different approach to ERP solicitations that uses sequential, rolling solicitations. WRA also proposes that Public Service develop and propose a

[306] CIEA's Comments, pp. 30-31.
[307] Interwest's Comments, p. 11.
[308] Interwest's Comments, p. 12.
[309] Conservation Coalition's Comments, pp. 18-20.

transparent scoring system for non-price factors, such as environmental compliance and community support.[310]

281. Arguing for higher-level changes to the ERP process, CEO raises concerns that the ERP process fails to develop a set of portfolios that are significantly different in terms of the resources considered or even the relative cost. Citing its proposals in Proceeding No. 19R-0096E for requiring electric utilities to submit various types of plans with their ERPs, CEO recommends that the Commission direct the Company to include scenario-type analysis as part of the 2026 ERP. CEO also encourages the Commission to re-open its ERP rules and adopt new rules that are more relevant to today's utility environment and that will help Colorado achieve its climate goals.[311]

282. Staff proposes that the Company explain in the 2024 JTS how it will update the effective load carrying capability (ELCC) and planning reserve margin (PRM) studies with the goal of accurately modeling portfolio level ELCC interactions to create reliable portfolios in EnCompass. Staff also recommends that Public Service work with Staff prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, meaningful demand side resources options, and inconsistent or unexplained modeling results.[312]

283. In its Response Comments, the Company does not oppose Staff's recommendation to include an explanation in the Pueblo JTP filing as to how it plans to improve the accuracy of modeling portfolio level ELCC interactions.[313] However, Public Service appears to disagree with

[310] WRA's Comments, pp. 25-29.
[311] CEO's Comments, p. 30.
[312] Staff's Comments, p. 74.
[313] Public Service's Response Comments, p. 104.

Staff's recommendation that the Company be required to work with Staff in the interim to develop more robust modeling processes.[314]

284. Regarding Conservation Coalition's recommendation that the Company conduct capacity accreditation studies and planning reserve studies in the same software tool, Public Service states that, as part of the Phase I Settlement, the Company has already committed to utilize the same modeling software and inputs for ELCC and PRM studies in future resource planning cycles and will also survey best practices in other jurisdictions when developing its methodology for these studies. The Company thus argues that the Phase II Decision does not need to reiterate this requirement.[315]

285. As for the arguments about increased information sharing, process improvements, and transparency, the Company asserts that no directives addressing these issues should be issued in this Proceeding. While Public Service acknowledges that there is always room for improvement in the resource planning and intervenor participation process, the Company argues that such issues are more appropriately resolved a part of a robust Phase I process in the 2024 JTS and the 2026 ERP.[316]

286. The Commission hereby adopts Staff's recommendations and will require Public Service to explain how the Company plans on accurately modelling portfolio level ELCC interactions in connection with its updated ELCC and PRM studies. We further direct the Company to confer with Staff and other interested parties prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, meaningful demand side resources options, and inconsistent or unexplained modeling results.

[314] Public Service's Response Comments, p. 112.
[315] Public Service's Response Comments, pp. 104-05.
[316] Public Service's Response Comments, pp. 111-12.

287. In contrast, we decline to adopt in this Phase II Decision the numerous other modeling and process proposals, including those proposed by party commenters that are expressly discussed above. Some of these proposals closely resemble topics that were adjudicated in Phase I (*e.g.*, making the modeling files available for other parties).[317] More generally, the Commission finds that it would be premature on this Phase II record to specify how the next ERP process will resolve these modelling and process issues. Nevertheless, as referenced above, we take seriously the numerous concerns that parties raised regarding how Public Service conducted the Phase II modeling, including the manual adjustments the Company made in Phase II and how difficult it was for the parties to analyze the impact of these adjustments. Likewise, we share many of the parties' concerns regarding the model's shortcomings as to issues such as curtailments and the interaction between new generation and transmission. While resolution of these issues for purposes of future ERP proceedings will benefit from a more robust record than is available to us during this Phase II, many of these concerns contribute to our decision to modify the CEP to include the Alternative Portfolio.

### 2. Non-Negotiable PPA Terms

288. Interwest asserts that the negotiating process on the model PPAs was not explained in advance and put some bidders at a significant and unexpected disadvantage. Interwest states that Public Service found several redlines to model PPAs unacceptable during the due diligence process, prior to actual PPA negotiations, but necessary to advance in the bid selection process. Interwest recommends that the Commission consider language in the Phase II decision specifying that only after a bid is selected should the PPA negotiations start, and Public Service should be

[317] Phase I Decision, ¶ 513.

prohibited from using the threat of bid elimination to force bidders to accept terms that this Commission has specifically intended to be negotiable.[318]

289. COSSA/SEIA similarly recommends that the Commission mandate that the Company identify which model PPA terms it considers non-negotiable, and that this be litigated in Phase I of future ERP proceedings so that all parties would enter Phase II on the same page about which terms are open to negotiation.[319]

290. CIEA claims that many IPPs felt bullied to identify model PPA-changes they would accept or forego the opportunity to raise such issues later in contract negotiation and were pressured to adopt Public Service's position just to remain in the evaluation process. CIEA recommends that the Commission direct a new approach that limits Public Service's ability to negotiate PPA terms with bidders during the bid evaluation process.[320]

291. In Public Service's Response Comments, the Company argues that the Commission should reject recommendations that would restrict the Company's ability to negotiate PPA terms with bidders during the bid evaluation process. The Company argues that to the extent bidders do not submit compliant bids, the Company must retain the ability to work with bidders to bring bids into compliance and ensure a viable and comparable bid pool. The Company does, however, support recommendations from CIEA and COSSA/SEIA that non-negotiable model PPA provisions be clearly set forth in its Phase I 2024 JTS filing and be formalized in the Commission's Phase I decision. Public Service states that doing so will provide additional clarity to bidders and

[318] Interwest's Comments, pp. 9-10.
[319] COSSA/SEIA's Comments, pp. 15-18.
[320] CIEA's Comments, pp. 32-35 ().

would help mitigate the need for extensive PPA contract discussions during the bid evaluation process.[321]

292. The Commission agrees with the IPP intervenors and the Company that there should be more clarity for bidders regarding what terms of the model PPA contracts are negotiable. We accordingly adopt Public Service's position and require the Company to clearly set forth the non-negotiable PPA terms in its Phase I 2024 JTS filing with the expectation that such terms will be formalized in the Commission's Phase I decision approving model PPAs.

293. As noted by Interwest and Public Service, "Colorado does not have a 'conforming bid' policy whereby bidders have to bid to the model agreements 'as-is.'"[322] However, having the Company and IE attempt to determine on an *ad hoc* basis during the bid evaluation process which terms of the PPAs are negotiable is a challenging situation. We acknowledge that it may be time for Colorado to move towards a conforming bid policy, especially considering that the Commission already addresses many core issues of the model PPAs in Phase I and the fact that in Phase II the Company and IE are called upon to equitably evaluate numerous bids. To be clear, the Commission is not in this Decision adopting any type of conforming bid policy, but we invite party feedback regarding adopting this type of approach in the future.

### 3. Company Ownership

294. Interwest takes issue with the high percentage of Company ownership in the portfolios presented in the 120-Day Report, arguing that it is outside of what was expected by virtually all parties. Interwest suggests that this calls into question the validity of the agreements in the Phase I Settlement regarding the amount of replacement capacity from the 2024 JTS that

[321] Public Service's Response Comments, p. 105.
[322] *See* 120-Day Report, p. 86; Interwest's Comments, p. 9.

Public Service would own. Interwest requests that the Commission consider whether Public Service achieved the letter and spirit of the law, whether the Phase I Settlement provisions regarding the ownership of Unit 3's replacement capacity are still valid, and whether action is necessary now to ensure compliance in future ERPs.[323]

295. CIEA similarly recommends that the Commission use the 2024 JTS to course correct and rebalance the resource ownership of IPPs and the Company in the total capacity mix of the system.[324]

296. Public Service urges the Commission to reject suggestions that the ownership percentage allowed in the 2024 JTS be adjusted to account for the high ownership the Company proposes in this Proceeding. Public Service argues that this recommendation could lock the Commission into higher-cost and uneconomic outcomes.[325]

297. The 2024 JTS is an interim ERP that will largely be governed by the Commission's ERP rules. We find that it would be inappropriate in this Phase II to attempt to set bounds around the Company ownership levels of the approved portfolio coming from the 2024 JTS. Moreover, we note that the selection of the Alternative Portfolio significantly reduces the amount of Company-owned capacity resources approved as part of this Proceeding as compared to the UPP.

#### 4. Just Transition Bids

298. UCA expresses disappointment that there were no bids for wind, solar, storage or solar plus storage at Craig or Hayden. UCA claims that such bids would have contributed to the just transition plan. UCA argues that these type of JTP bids should be encouraged at Craig and

[323] Interwest's Comments, p. 9.
[324] CIEA's Comments, p. 18.
[325] Public Service's Response Comments, pp. 33-34.

Hayden and other west slope locations as well as in the Pueblo area. UCA goes on to suggest that such bids could even be required from Public Service.[326]

299. Although we refrain from creating any sort of requirement for certain bids, we agree with UCA's sentiments about the benefits of bids at Craig, Hayden, and Pueblo and encourage such bids in the upcoming 2024 JTS. We further encourage bids within the Denver Metro area to the extent such bids can mitigate the need for additional transmission investments.

300. The 2024 JTS offers the state an important opportunity to continue acquiring renewable resources to achieve even greater emissions reductions while addressing some of the issues that arose in this Proceeding. Consistent with the Phase I Settlement Agreement, however, we reiterate that the 2024 JTS is the proceeding that will acquire a suitable replacement for the capacity that will be lost when Unit 3 retires and that all parties should work to ensure that the Pueblo community and benefits to the community are the focus of this replacement.[327] In this vein, we note that nothing in this Phase II Decision impacts the Company's commitment in the Phase I Settlement to "make payments to Pueblo County annually from 2031 through 2040 … in the amount of the projected lost property tax revenues for those years, unless offset by property tax revenues from generation or transmission infrastructure sited at Comanche Station or within Pueblo County."[328]

[326] UCA's Comments, p. 20.
[327] *See* Phase I Decision, p. 43; Phase I Settlement, ¶ 43.
[328] Phase I Settlement, ¶ 42.

### 5. Discount Rates

301. Conservation Coalition suggests that the Commission direct the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the June 2024 JTS.[329]

302. While consideration of lower discount rates does not warrant the selection of a different resource portfolio in this Proceeding (as set forth above), we find merit in the Conservation Coalition's request that Public Service attempt to reach consensus with stakeholders on the related issue of discounting the social cost of emissions. Accordingly, we grant Conservation Coalition's request and direct the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the 2024 JTS. This conferral should include the impacts of SB 23-291 regarding the appropriate discount rate to use for fuel costs.

### 6. Comprehensive Rate Analysis

303. In the 120-Day Report, Public Service states that "the average bill impact for the Preferred Plan is expected to grow less than the historical rate of inflation."[330] Staff, UCA, and CEC argue, however, that the costs presented in the 120-Day Report are likely to be artificially low.[331] Staff in particular states that there is additional anticipated investment that is not included in the Company's rate impact analysis. Staff asserts that the Company's statement regarding the cumulative average growth rates was carefully worded to include only the incremental rate impact of the CEP, not the rate impact of the entirety of the Company's planned investments including

[329] Conservation Coalition's Comments, pp. 21-22.
[330] 120-Day Report, p. 34.
[331] Staff's Comments, p. 19; UCA's Comments, pp. 5-7; CEC's Comments, pp. 15-16.

distribution system investment, other transmission system investment, and additional electric generation not included in this Proceeding.[332]

304. Given the importance of affordability, the Commission and interested stakeholders should have access to a consistent view of Public Service's capital expansion plan for the Colorado electrical system and what this plan means for ratepayers. Accordingly, the Commission directs Public Service to provide in the 2024 JTS a comprehensive long-term rate analysis that fully includes all of the projected investments the Company is communicating to the financial community, including for new distribution investment, wildfire mitigation, transmission upgrade, transportation electrification, distributed solar, and other electricity business investments.[333] This comprehensive rate analysis should also include an analysis that better quantifies the actual levels of resource curtailment above the modelled levels and, in format, should be similar to the rate forecast models the Company has recently presented in rate cases.

305. We emphasize that this comprehensive rate analysis shall not be limited to projects that have received official regulatory approval or projects that have final cost estimates. Rather, this comprehensive rate analysis shall include all projected investments in the Colorado electric system that Public Service is communicating to the financial community and any that are reasonably expected.

## R. Miscellaneous Issues for Future Proceedings

### 1. Equity Directives

306. In its Comments on the 120-Day Report, Staff notes the importance of evaluating ERP proceedings through an equity lens. Staff further notes that as part of the solicitation that the

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[332] Staff's Comments, p. 19.

[333] Consistent with prior filing expectations, documents are expected to be as robust as possible and in executable format.

Company performed in this Proceeding, all bidders were required to provide information on the assessment of, and plan for continuing to monitor local community, disproportionately impacted (DI) community, and state reaction to the bidder's proposed project, and a plan to work with the local community and DI communities on project issues. In addition, as part of the 120-Day Report, the Company provided maps that identify which projects are located in DI communities.[334]

307. After assessing the information that was received in this Proceeding, Staff makes a series of recommendations that the Commission could take in future proceedings to continue to improve the Commission's consideration of equity issues. For example, Staff argues that in the future, the 120-Day Report should include a more detailed analysis of community/state reaction, which goes beyond identifying the DI communities. Staff also suggests that the Commission consider developing rules that (1) identify key metrics that should be reported by bids in DI communities to help understand impacts and benefits of bids on DI communities, and (2) define a process for tracking stakeholder engagement in bids approved in the resource plan in DI communities. Finally, Staff recommends that the Commission consider specifying how it will consider equity metrics in decision making and document the consideration of energy equity issues in written decisions prior to approvals for Resource Plans, Plan amendments, and CPCNs.[335]

308. In a similar vein, CEO notes with approval how the Company mapped the bids in this Proceeding relative to DI Communities. CEO encourages a similar presentation of mapping in the Company's next ERP and notes the expectation that the Commission will continue to consider how it will use such mapping in its decision making going forward.[336]

[334] Staff's Comments, pp. 69-70.
[335] Staff's Comments, pp. 71-72.
[336] CEO's Comments, pp. 24-25.

309. In its Response Comments, the Company expresses appreciation for Staff's recommendations as the consideration of equity issues in resource planning continues to evolve. The Company notes that it has expanded the scope and reach of its community engagement efforts and expects to continue this expansion. Public Service further expects that the presentation and evaluation of equity issues will continue to improve, similar to how the BVEM bid information and evaluation process has improved. Public Service states that it welcomes and encourages continued discussion in the next ERP Phase I process and in future Just Transition Plan proceedings to ensure meaningful consideration of equity issues but that the Company does not believe specific requirements need be prescribed in rules.[337]

310. We acknowledge and appreciate the considerations from Staff and CEO regarding how to continue improving the Commission's consideration of equity issues in future ERP proceedings and rulemakings. At this juncture, however, we will leave it to the relevant stakeholders to work out the appropriate specifics on when and how best to further advance the consideration of equity issues in resource planning. We note that in Proceeding No. 22M-0171ALL the Commission has an ongoing and far-reaching pre-rulemaking underway aimed at improving equity outcomes in the State through reforms to practices, outreach, and rules. The Commission encourages stakeholders to provide comments within that pre-rulemaking proceeding where we are diligently collecting concepts on what rules should be considered and addressed in order to promote equity.

### 2. CPCN Prioritization

311. CIEA and Conservation Coalition both encourage the Commission to proactively manage the applications for CPCNs that the Company will eventually file for each utility-owned

[337] Public Service's Response Comments, pp. 107-08.

generation asset included in the approved resource portfolio. For instance, noting the large amount of expected CPCN filings, CIEA recommends that there be a priority established for 2024 CPCNs based on the value to ratepayers of the various projects. Denver metro transmission projects with 2030 ISDs could be delayed to later but generation projects that are critical to system or local reliability should be prioritized.[338]

312. Similarly, the Conservation Coalition suggests that the Commission consider how it can reduce the litigation burden to parties (and the burden on the Commission) of the CPCNs arising from this Proceeding. The Conservation Coalition specifically recommends one of two solutions for consolidating the various CPCNs. The first proposal is to require the Company to confer with all parties and file a reporting containing the proposals for how best to consolidate and minimize the number of CPCN applications. The Commission would then issue an order in this Proceeding addressing consolidation. The second proposal is to simply order the Company to consolidate its CPCN applications based on some criterion or criteria (*e.g.*, technology type or ISD).[339]

313. In its Response Comments, Public Service argues that it has the responsibility to timely file CPCNs and that the Company will need some flexibility to do so. However, the Company proposes providing updates to interested parties and the Commission on the status of CPCN filings in its Annual ERP Reports that it files every year on March 31 as well as in its annual Rule 3205 and Rule 3206 reports. Public Service argues that these existing reporting venues provide the appropriate opportunity for the Company to update stakeholders on CPCN filing

[338] CIEA's Comments, pp. 8, 35-36.
[339] Conservation Coalition's Comments, pp. 22-23.

readiness as well as the anticipated filing dates, sequencing, and grouping of generation and transmission CPCNs moving forward post-Phase II.[340]

314. We adopt Public Service's position set forth in its Response Comments and direct the Company to provide additional updates to interested stakeholders regarding the Company's CPCN prioritization via the existing reporting venues. At this juncture, the Commission will not attempt to dictate the form or timing of Public Service's CPCN and other applications.

### 3. Voluntary Additional Emissions Reduction Program

315. Boulder recommends the Commission direct Public Service and interested communities and customers to explore acquiring additional resources to support development of a voluntary customer product that generates additional emissions reductions. Boulder asserts that "communities comprising at least 35 percent of Public Service retail sales seek '100% renewable energy' or zero emissions electricity by 2030."[341] Given the importance of decarbonizing the electricity sector as soon as possible to support decarbonization in other sectors like buildings and transportation, Boulder argues that "the time is now to develop next-generation voluntary customer products that quantify incremental emissions reductions."[342]

316. Boulder acknowledges that the Phase I Settlement contains a commitment for Boulder and Public Service to work together to develop such a voluntary program. Boulder indicates that, based on preliminary modeling, it appears that acquiring additional renewable resources could generate incremental emissions reduction but at the significant risk of curtailments. In addition, according to Boulder, the preliminary modeling showed that incremental

[340] Public Service's Response Comments, pp. 100-02.
[341] Boulder's Comments, p. 17.
[342] Boulder's Comments, p. 17.

costs of such additional resources "suggests that new voluntary emissions reduction products must be available to all Public Service customers and not limited to one community or customer."[343]

317. Boulder asserts that the bids received in Public Service's solicitation provide options for the development of a new voluntary emissions reduction product that would enable communities and customers to progress towards their 100 percent renewable energy goals. Boulder suggests that bids included in the Preferred Portfolio could be expanded to add generation or storage, and this expansion could be funded by communities and customers participating in the voluntary emissions reduction program. Boulder also asserts that there are bids that were not included in the Preferred Portfolio, including Section 123 Resources, the acquisition of which could be supported by customers interested a voluntary emissions reduction program.

318. The Commission understands that certain communities and organizations would prefer to exceed the environmental attributes of Public Service's general resource mix via a more robust, voluntary offering and believe such a program is feasible. We are interested in better understanding what steps the Commission could put in place to provide such a voluntary program for customers and communities and how the tracking would work to ensure that the program would not dilute the environmental attributes of the general resource mix or unfairly allocate costs.

319. Accordingly, we direct Public Service and Staff of the Commission[344] to work together with interested parties to discuss this topic at a CIM. The discussion could include information regarding what stakeholders are interested in, what attributes are desired, the potential structure of such a program, the status of Public Service's efforts on this topic, and what the next steps are. We are hopeful that this CIM could be convened in late February or early March.

[343] Boulder's Comments, p. 18.
[344] This could be either Trial Staff or staff of the Commission's Research and Emerging Issues group.

### S. Requests not Explicitly Addressed

320. The Commission has weighed the information and filings from all parties and public commentors in balancing its policy and reaching the various decisions set out in this Phase II Decision. To the extent this Phase II Decision does not expressly address requests made by Public Service or an intervening party, such requests are denied. However, these requests were considered in balancing our considerations and reaching our ultimate conclusions in this Proceeding.

## II. ORDER

### A. The Commission Orders That:

1. After consideration of the statutory factors and other relevant factors, modifications to the Clean Energy Plan (CEP) presented by Public Service Company of Colorado (Public Service) are necessary to ensure that the Commission's approval of the CEP is in the public interest.

2. In accordance with the discussion above, we authorize Public Service to pursue the modified CEP and the acquisition of the resources included in the Alternative Portfolio with further due diligence and contract negotiations. Public Service shall further file applications for Certificates of Public Convenience and Necessity for all Company-owned generation resources arising from the modified CEP. Public Service's actions, consistent with this Decision, shall be presumed to be prudent at the time of cost recovery consistent with 4 *Code of Colorado Regulations* (CCR) 723-3-33617(d) of the Commission's Rules Regulating Electric Utilities.

3. All Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM, in accordance with the discussion above.

4. The proposed transmission network upgrades, grid strength reinforcements, reactive power investments, and voltage support investments presented in the 120-Day Report are not part of the approved CEP. Additional review of the proposed transmission projects is necessary and, accordingly, 4 CCR 723-3-3206 is waived as to the transmission projects arising from this Proceeding, in accordance with the discussion above.

5. In accordance with the discussion above, Staff of the Colorado Public Utilities Commission (Staff) shall also initiate a stakeholder process with the Colorado Office of Utility Consumer Advocate and the Colorado Energy Office and in conferral with Public Service to bring forward a scope of work for hiring an independent transmission analyst as soon as reasonably feasible but no later than the commencement of the 2024 Just Transition Solicitation (JTS) proceeding. If this independent transmission analyst cannot be engaged in time for Phase I of the 2024 JTS, we direct the Company to include certain transmission-related portfolios in its direct case, in accordance with the discussion above.

6. As part of its application regarding attribution of costs between the CEP rider (CEPR) and the Renewable Energy Standard Adjustment, the Company shall address the recovery of specific activities based on the approved resource portfolio and the appropriate level for the CEPR to be initiated on January 1, 2025, in accordance with the discussion above.

7. With respect to the 2024 JTS, Public Service shall confer with Staff prior to the 2024 JTS to develop more robust modeling processes, clearly set forth the Company's proposed non-negotiable PPA terms in its Phase I 2024 JTS filing and provide in the 2024 JTS a comprehensive long-term rate analysis in addition to our other directives in accordance with the discussion above.

8. Public Service and Staff of the Commission shall work together to present at an upcoming Commissioners Information Meeting the interest in, potential structure of, and current efforts to develop a voluntary emissions reduction program, in accordance with the discussion above.

9. The 90-day deadline for a written Phase II Decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan set forth in 4 CCR 723-3-3613(h) is waived.

10. To the extent requests are not addressed in this Decision, they are denied.

11. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

12. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS December 6, 13, and 20, 2023.**

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

<table>
<tr><td>Federal Power Act Section 202(c)<br>Emergency Order: Tri-State<br>Generation and Transmission<br>Association, Platte River Power<br>Authority, Salt River Project,<br>PacifiCorp, and Xcel Energy</td><td>)<br>)<br>)<br>)<br>)<br>)</td><td><br>Order No. 202-26-21</td></tr>
</table>

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-165
Colorado Commission Decision No. C25-0024

Decision No. C25-0024

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

**COMMISSION DECISION GRANTING, IN PART, AND DENYING, IN PART, THE MOTION TO APPROVE THE CLEAN ENERGY PLAN DELIVERY PLAN**

Issued Date: January 14, 2025
Adopted Date: December 16, 2024 and December 20, 2024

**TABLE OF CONTENTS**

# I. BY THE COMMISSION

## A. Statement

1. On September 6, 2024, Public Service Company of Colorado ("Public Service" or the "Company") filed a Motion to Approve Clean Energy Plan ("CEP") Delivery Plan and for Variances from Certain Commission Rules and Decisions ("CEP Delivery Motion").

2. Through this Decision, the Commission grants, in part, and denies, in part the CEP Delivery Motion. Our Decision allows the generation and storage projects included within the CEP to continue advancing despite changing market dynamics and geopolitical uncertainties, including importantly potential future changes in federal law. Advancing these generation and storage projects as part of the overall determinations made through the course of this Proceeding moves Colorado forward towards achieving aggressive state emission reduction targets. At the same time, while some amount of price flexibility is necessary, particularly given reliability and emission reduction considerations, our Decision also balances this price flexibility with several protections to ensure the CEP comes at a reasonable cost to customers. These protections include a two-stage process for clean energy projects that caps the amount of price relief and permits intervenor and Commission review as well as using existing regulatory processes for additional investigation and review of price increases associated with utility-owned projects. Similarly, this Decision finds that the record and abbreviated process associated with the CEP Delivery Motion are insufficient to make certain requested findings regarding additional thermal capacity and proposals to modify a demand responses ("DR") program. As set forth below, the Company is in no way prohibited from making appropriate filings to move these or other endeavors forward, particularly as it ensures reliability.

3. These determinations provide a process in consideration of the CEP Delivery Motion enabling timely review should federal changes in law arise that impact bid pricing, concurrent with guidance towards longstanding Commission processes. This careful balance and necessary flexibility to move towards significant emission reduction targets, while protecting Colorado ratepayers, including by allowing ongoing scrutiny, particularly of utility-owned projects not yet demonstrated as warranting a presumption of prudence.

**B. Procedural History**

4. Public Service initiated this Proceeding by filing its Verified Application for Approval of its 2021 Electric Resource Plan ("ERP") and CEP on March 31, 2021.

5. On August 3, 2022, the Commission issued Decision No. C22-0459 ("Phase I Decision"). Among other things, the Phase I Decision authorized Public Service to implement a competitive bidding process for acquiring cost-effective resources to meet its projected resource need from 2022 through 2028. The Commission also approved the process for evaluating bids to the competitive solicitation and established the modeling parameters, including inputs and assumptions, for the presentation and consideration of potential resource portfolios in Phase II of the Commission's ERP process. Pursuant to the terms of the Updated Non-unanimous Partial Settlement Agreement approved, in part, by the Phase I Decision, the Commission further authorized Public Service to initiate an interim ERP called the Just Transition Solicitation ("JTS") focused on meeting the projected resource need for the years 2029, 2030, and 2031.[1]

6. On January 23, 2024, the Commission issued Decision No. C24-0052 ("Phase II Decision"), approving the Company's CEP with modifications. Among other things, the Phase II

[1] Public Service filed an Application for Approval of its Just Transition Solicitation on October 15, 2024 in Proceeding No. 24A-0442E ("JTS Proceeding"). The JTS Proceeding is ongoing.

Decision authorized Public Service to pursue the acquisition of more than 5,800 MW of new storage and generation projects that were included in the approved resource portfolio with further due diligence and contract negotiations.[2] The approved resource portfolio includes 669 MW of thermal resources, consisting of four separate projects: Bid 0989 (a 200 MW Company-owned unit), Bid 0997 (a 200 MW Company-owned unit), Bid 0011 (a 50 MW unit that would be developed and constructed by a third-party but ultimately owned by the Company), and Bid 0235 (a 219 MW power purchase agreement ("PPA") unit). The Commission found that the inclusion of the PPA thermal resource (Bid 0235) was attractive in that it reduces the risk that customers will bear future costs associated with utility-owned gas resources, including the risks that utility-owned gas resources will become stranded.[3]

7. The Phase II Decision also established a cost-to-construct ("CtC") performance incentive mechanism ("PIM") for each utility owned generation and storage project in the approved resource portfolio. In the Phase II Decision, the Commission recounted how in other contexts, costs, performance, or scheduling issues have increased the costs of utility-owned projects relative to the initial estimates the Company provided.[4] The Commission opined that material changes to the cost and performance metrics of a project could impact the justification of the ERP need determinations. In addition, with competitive solicitation being the lynchpin of Colorado's ERP process, we opined that winning bidders should not be able to materially increase the price of bids without consequences.[5] To incentivize Public Service to build utility-owned projects at or below budget, the Commission established the CtC PIM that used the as-bid capital

[2] Phase II Decision, ¶ 92.

[3] Phase II Decision, ¶¶ 101 108.

[4] The Commission gave the specific example of the Company's representations in Phase I of the proceeding that the conversion of the Brush Coal Plant to burn gas would cost approximately $44 million. In the subsequent CPCN application, however, the Company's estimated costs had increased to $85 million. (Phase II Decision, ¶ 180).

[5] Phase II Decision, p. 125.

construction cost for each project as the baseline, set a five percent deadband around the baseline, and then set three symmetric tiers of costs sharing if the actual construction costs for a project were above or below the deadband.[6]

8. In the Phase II Decision, the Commission directed Public Service to file applications for Certificates of Public Convenience and Necessity ("CPCN") for all utility-owned resources within the approved resource portfolio. The Commission noted that, consistent with 4 *Code of Colorado Regulations* ("CCR") 723-3-3617(d) of the Commission's Rules Regulating Electric Utilities, Public Service's actions that are consistent with the Phase II Decision have a presumption of prudence.[7]

9. On March 13, 2024, the Commission issued Decision No. C23-0672 Addressing Applications for Rehearing, Reargument, or Reconsideration ("RRR") of the Phase II Decision ("First RRR Decision"). The First RRR Decision addressed several issues, including challenges to the approved resource portfolio, proposed modifications to the established CtC PIM, and the appropriate process for selecting backup projects. In addition, the First RRR Decision addressed the replacement of Bid 0235, which became unavailable after the Phase II Decision. The Commission specifically rejected the Company's request to replace Bid 0235 (a PPA project) with Bid 1000 (a utility-owned project). The Commission reiterated that diversifying the ownership of the gas resources can help reduce risks to ratepayers and expressed a strong interest in evaluating whether there were other PPA gas resources that could replace Bid 0235, such as Bid 0510, Bid 0514, and Bid 1061.[8]

[6] Phase II Decision, ¶¶ 183-185.
[7] Phase II Decision, p. 125.
[8] First RRR Decision, pp. 34-35.

10. On September 6, 2024, Public Service filed the CEP Delivery Motion, along with the testimony of Jack Ihle and several attachments. Among other things, the CEP Delivery Motion puts forth a proposed procedural schedule and limited discovery rights to facilitate the Commission's review of the Motion.

11. On September 10, 2024, Climax Molybdenum Company ("Climax") filed a Response to Public Service's proposed procedural schedule, which the Office of Utility Consumer Advocate ("UCA") and the Colorado Energy Consumers ("CEC") join. In the Response, Climax acknowledges the urgency of the CEP Delivery Plan but argues for extending the deadline for intervenor responses and increasing the amount of discovery that parties can propound. In its Response, Climax further states it prefers to proceed with an evidentiary hearing.

12. On September 19, 2024, the Commission issued Decision No. C24-0678-I. Among other things, Decision No. C24-0678-I set a procedural schedule that required the Company to file supplemental information, followed by intervenor responses, and a reply from Public Service to those responses ("Reply Comments"). Decision No. C24-0678-I also established limited discovery rights and scheduled a two-day *en banc* evidentiary hearing. The procedural schedule and discovery limits were a compromise approach that balanced the need for expediency and the concerns that certain intervenors raised regarding the deadline for intervenor responses and the amount of discovery rights afforded.[9]

13. By Decision No. C24-0699-I,[10] the Commission addressed both UCA's request to shorten the timeline for Public Service to respond to discovery and certain recommendations regarding Plains End (an existing PPA thermal resource). In addition, we invited the parties to

[9] Specifically, the concerns set forth in Climax's Response to Public Service's proposed procedural schedule. As set forth above, Climax argued for extending the deadline for intervenor responses and increasing the amount of discovery. UCA and CEC joined Climax's Response.

[10] Issued September 26, 2024.

comment on a proposed approach to maintain competitive tension and directed Public Service to provide additional information regarding certain wind and thermal bids.

14. On October 4, 2024, Public Service filed supplemental comments and information, pursuant to Decision No. C24-0678-I. Included in this supplemental filing was Hearing Exhibit 166, Attachment JWI-17. This Attachment is a detailed report on the status of all bids and includes information from the bidders regarding whether they are able to move forward with their as-bid pricing and the scope of price relief many bidders assert they need to move forward with their projects. Public Service submitted a revised version of this Attachment on November 1, 2024.

15. On October 11, 2024, the following intervenors filed Answer Testimony to the CEP Delivery Motion: Staff, the Colorado Energy Office ("CEO"), UCA, and the Colorado Solar and Storage Association and the Solar Energy Industries Association ("COSSA/SEIA"). In addition, the following parties filed Comments on the CEP Delivery Motion: the Colorado Independent Energy Association ("CIEA"), Interwest Energy Alliance ("Interwest"), Western Resource Advocates ("WRA"), and CEC.[11]

16. On October 3, 2024, Mainspring Energy, Inc. ("Mainspring"), filed an unopposed motion to intervene out of time in this Proceeding ("Late Intervention"). Mainspring is the developer of Bid 0011, which is a 50 MW new-build thermal resource in the San Luis Valley. Mainspring has been negotiating a build-transfer agreement with Public Service in which the Company will ultimately own and operate Bid 0011. In its Late Intervention, Mainspring argues the CEP Delivery Motion could directly and substantially impact Mainspring.

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[11] Climax as well as UCA support and join in CEC's comments.

17. By Decision No. C24-0736-I,[12] the Commission granted Mainspring's Late Intervention. The Commission found that Mainspring sufficiently demonstrated its interests in this Proceeding and noted that no party opposes the Late Intervention.

18. On October 11, 2024, Mainspring filed Answer Testimony from two witnesses.

19. In Decision No. C24-0746-I,[13] the Commission directed Public Service to provide additional information in its Reply Comments. The Commission required the Company's Reply Comments to include the relevant PPA and build transfer agreement provisions that would implement a change-in-law price relief mechanism as well as examples of the PPA provisions that allegedly pose an unacceptable level of risk to the Company.

20. On October 25, 2024, Public Service submitted its Reply Comments.

21. On November 1, 2024, Mainspring filed an unopposed motion requesting access to certain confidential and highly confidential information pertaining to Bid 0011 ("Unopposed Motion to Access Information").

22. By Decision No. C24-0805-I,[14] the Commission granted Mainspring's Unopposed Motion to Access Information.

23. On November 7, 2024, the Commission held a remote evidentiary hearing at which the following exhibits and associated attachments were admitted: Hearing Exhibits 166, 509, 1205, 2202, 2204, 2709, 2710, 2711, 2712, 2713, 2714, 2715, 2716, 2717, 2718, 2719, 2720, 2721, 2722, 2723, 2725, 2904, 3000, and 3001.

24. On November 18, 2024, the following parties filed statements of position ("SOPs"): Public Service, Staff, UCA, CEC,[15] CIEA, COSSA/SEIA, Interwest, Mainspring, and WRA.

[12] Issued October 11, 2024.
[13] Issued October 16, 2024.
[14] Issued November 6, 2024.
[15] Climax supports and joins CEC's SOP.

25. The Commission deliberated on the CEP Delivery Motion at the December 16, 2024 Commissioner's Deliberations Meeting ("CDM") and the December 20, 2024 CDM.[16]

### C. Background of the CEP Delivery Motion

26. In the CEP Delivery Motion, Public Service argues that global and national geopolitical and market forces require some adjustments to the CEP to ensure the generation and storage projects contemplated in the approved resource portfolio can move forward.[17] Public Service categorizes its requests into three components. Component 1 consists of a two-stage process in which renewable energy and storage projects could request price relief.[18] Under this process as initially proposed, developers (including the Company) could individually submit requests to a newly appointed Independent Auditor ("IA") to increase the price of their projects based on things such as unexpected supply chain difficulties, recent changes in tariff policy, or future changes in federal law. The IA would then verify whether the requested price increase is justified and submit its verification decision to the Commission for review.[19]

27. Under Stage 1 of this first component, developers could base price increase requests on a broad set of circumstances such as known and pending tariffs or duties, supply chain issues, or any other impacts of current market conditions such as changes in costs of materials or labor.[20] As proposed in the CEP Delivery Motion, developers could receive Stage 1 price relief of up to six percent increase of the as-bid pricing. Under Stage 2 of Component 1, developers could submit price increase requests to the IA based on a specified changes in federal law such as new tariffs or

[16] The procedural history and background of this case are more fully set forth in the Phase II Decision and the First RRR Decision. Here, we provide only that background and procedural history necessary for this Decision.
[17] CEP Delivery Motion, p. 2.
[18] Hr. Ex. 166 (Ihle), p. 35.
[19] Hr. Ex. 166 (Ihle), pp. 40-41.
[20] Hr. Ex. 166 (Ihle), pp. 35-36.

the reduction or repeal of the currently available production tax credits ("PTCs") or investment tax credits ("ITCs").[21] Developers could receive additional price relief in Stage 2 up to a total of 15 percent, inclusive of any Stage 1 relief. Thus, if a project received a six percent price relief in Stage 1, it would only be eligible for up to an additional nine percent increase in Stage 2.[22]

28. Component 2 addresses the thermal resources contemplated in the approved resource portfolio. Similar to the renewable energy and storage projects in Component 1, Public Service argues that the thermal resources need price increases to address disruptions to supply chains, strong demand for thermal unit components and labor, and the length of time that has elapsed since the bids were initially submitted on March 1, 2023.[23] Public Service seeks the ERP presumption of prudence per Rule 3617(d) that moving forward with the thermal units at the new revised cost levels is prudent. In addition, Public Service asks that the CtC baseline for the utility-owned gas facilities be adjusted upward to match the new cost estimates.[24]

29. Component 2 includes the Company's request for Commission approval to replace Bid 0235 with Bid 1000. Bid 0235 (a 219 MW new-build PPA gas resource) was included in the approved resource portfolio but is no longer available. The Company also seeks authorization to not include the selective catalytic reduction ("SCR") system that it originally planned for Bid 0989 (a 200 MW, utility-owned gas unit).[25]

30. As an alternative to Components 1 and 2, Public Service suggests the Commission treat utility-owned projects as "a distinct portfolio." Under this alternative, the projects in the utility-owned portfolio would keep the same construction costs that the Phase II Decision

[21] Hr. Ex. 166 (Ihle), p. 52.
[22] Hr. Ex. 166 (Ihle), p. 51.
[23] Hr. Ex. 166 (Ihle), p. 57.
[24] Hr. Ex. 166 (Ihle), pp. 57-58.
[25] Hr. Ex. 166 (Ihle), pp. 88-89.

contemplates, but instead of several project-specific PIMs, there would be one portfolio-wide PIM with a five percent deadband.[26] PPA projects could continue to seek price relief under the proposed Component 1 process.[27]

31. In Component 3, the Company requests approval to take certain actions to address near-term resource adequacy concerns by increasing capacity. Specifically, the Company requests a PPA extension for Plains End (a 219 MW unit with a PPA that expires at the end of 2027)[28] and increasing the incentives in the interruptible service option credit ("ISOC") program in an attempt to boost DR capacity.[29] Initially, Public Service also requested as part of Component 3 an extension of Bid 1061 (a 76 MW PPA thermal resource).[30] However, Bid 1061 subsequently became unavailable.[31]

## D. Component 1, Stage 1

### 1. Party Positions

32. As initially presented, in Stage 1 of Component 1, both utility-owned and PPA clean energy resources could obtain price increases of up to six percent due to current market conditions. To receive such pricing relief, developers would submit requests and supporting information to the IA, and the IA would make a project-specific determination of whether the price increase is legitimate reasonable or whether it was due to an unreasonably low bid estimate. In their SOPs, however, several parties, including Public Service, Staff, CIEA, and COSSA/SEIA argue the Commission should fundamentally modify the proposed Component 1, Stage 1 process by eliminating the IA review process.

[26] CEP Delivery Motion, pp. 2-3.
[27] Hr. Ex. 166 (Ihle), p. 90.
[28] Hr. Ex. 166 (Ihle), p. 114.
[29] Hr. Ex. 166 (Ihle), p. 101.
[30] Hr. Ex. 166 (Ihle), pp. 112-13.
[31] Hr. Ex. 166 (Attachment JWI-16), p. 20.

33. Public Service specifically recommends that the Commission apply a uniform one to three percent price increase, without further IA reviews. Public Service “suggests 2 percent but defers to the independent power producer (“IPP”) trade associations on the specific level of relief.”[32] For wind projects, Public Service recommends the Commission apply a six percent price increase.[33] PPA projects would receive the approved price increase if the bidder can provide an affidavit of a corporate officer for the IPP bidder supporting the causes of the price increase. Any project that takes a Stage 1 increase would remain eligible for a Stage 2 change-of-law adjustment, and no increase could exceed 15 percent in aggregate, as initially proposed in the CEP Delivery Plan.[34]

34. For utility-owned clean energy projects, Public Service “would provide sworn testimony in support of the increase to the CtC value in the CPCN proceeding….”[35] The individual PIMs would be built around this updated CtC value and the CtC baseline would be entitled to a presumption of prudence in the follow-on CPCN proceeding.[36] For the three utility-owned wind projects in particular, Public Service makes clear in its SOP that the Company’s sworn testimony in the CPCN proceeding would support an increase in the CtC value, “which may not exceed 6 percent.”[37] Consistent with its initial proposal, Public Service argues that the price increases should be based on the $/MWh or $/kW-month PPA rates for IPP projects and should be based on the construction costs for utility-owned projects.[38]

[32] Public Service’s SOP, p. 2.
[33] Public Service’s SOP, p. 2.
[34] Public Service’s SOP, p. 8.
[35] Public Service’s SOP, p. 8.
[36] Public Service’s SOP, pp. 8, 13.
[37] Public Service’s SOP, p. 8.
[38] Hr. Ex. 166 (Attachment JWI-16), p. 13.

35. CIEA also recommends eliminating the use of the IA and instead requiring IPPs to submit affidavits signed by corporate officers supporting each CEP Project's repricing request. IPPs would provide the affidavits to Public Service, who could report the information to the Commission. Under this "fast-track" approach, CIEA would support a technology-specific reduced pricing flexibility of an up to three percent increase for solar, storage, or hybrid projects and up to six percent pricing flexibility for wind projects.[39]

36. As support for this position, CIEA argues that "[d]elay is the enemy" and that each month of delay causes cost increases.[40] CIEA argues that under Public Service's initially proposed IA process, the IA might not realistically complete its review of repricing submittal until approximately April 2025.[41] CIEA asserts that "the benefits of rigorous project pricing flexibility oversight via an IA and more regulatory process are outweighed by the risks of further increased project costs and decreased generation for resource adequacy in 2027 and 2028 due to project withdrawals or inability to meet as-bid [commercial operation dates]."[42]

37. COSSA/SEIA similarly argues against the IA approach in Stage 1. COSSA/SEIA acknowledges the IA may offer checks and balances and provide additional information but argues the IA process will introduce at least four additional months of delay.[43] Instead, COSSA/SEIA recommends the Commission authorize a three percent across-the-board price increase for solar, solar plus storage, and storage projects now based on the record associated with the CEP Delivery Motion filings. COSSA/SEIA argues this will avoid additional delays and price increases that could occur between now and March 2025. COSSA/SEIA states that it "is confident that increasing

[39] CIEA's SOP, p. 3.
[40] CIEA's SOP, p. 7.
[41] CIEA's SOP, p. 8.
[42] CIEA's SOP, p. 11.
[43] COSSA/SEIA's SOP, p. 3.

bid pricing by this amount will allow projects to get across the finish line toward contract execution."[44]

38. COSSA/SEIA questions the accuracy of the developer survey answers reflected in Hr. Ex. 166, Attachment JWI-17, Rev. 1, which reports the status of all of the projects and the scope of the requested price increases. COSSA/SEIA asks the Commission to refrain from exclusively relying on the information within this attachment, suggesting that the information is inaccurate and outdated.[45]

39. In its SOP, Interwest supports any plan that meets certain attributes that would help provide a quick path to project finalization. For Stage 1, Interwest's desired attributes include eliminating or minimizing the timeline and complexity of any IA process or additional regulatory review and incentivizing projects to sign agreements as soon as possible.[46]

40. In its SOP, Staff recommends adopting CIEA's initial proposal in which clean energy resources could request a price increase of between two to six percent by submitting affidavits of corporate officers to the Company, and the Company would then confirm this repricing in a compliance filing to the Commission.[47] Projects that do not require Stage 1 price relief should be expedited, remain eligible for Stage 2 relief (change of law), and could receive a one percent price increase without verification. Staff argues this option represents the best overall

[44] COSSA/SEIA's SOP, p. 11.
[45] COSSA/SEIA's SOP, pp. 6-7.
[46] Interwest's SOP, p. 1.
[47] While CIEA modified its position somewhat in its SOP, it initially proposed allowing IPPs to receive a price increase up to six percent in Component 1, Stage 1 without any IA review, with the understanding that such Stage 1 price increases could later be clawed back in Stage 2. Developers who are willing to execute PPAs right away could qualify for a one percent price increase without bidirectional Stage 2 exposure. (CIEA's CEP Delivery Response Comments, pp. 17-18).

approach to achieving price relief and that eliminating the IA will accelerate the development of all renewable projects.[48]

41. If the Commission moves forward with this approach, Staff argues two clarifications are necessary. First, the approach applies both to PPAs and utility-owned projects. For utility-owned projects, the Company would submit a filing with the Commission attesting to the need for the price increase. Second, Staff recommends the Commission specify that this price relief approach applies to projects in the approved portfolio. Only after an approved project has failed and the Company has gone through the established process for advancing backup bids could a backup bid also be eligible for Stage 1 price relief.[49]

42. In connection with its recommendation to approve pricing relief in Stage 1, Staff argues that the Commission should treat utility-owned generation and PPAs the same by applying a six percent price relief limit to the project's net present value ("NPV") for both ownership types as opposed to a six percent NPV for PPA projects and a six percent CtC baseline increase for utility projects. Staff argues the Commission should ignore the Company's protests and fashion the price relief for both PPAs and utility projects such that it is based on the NPV of the projects.[50]

43. In contrast to the parties arguing for the elimination of the IA, UCA recommends the Commission approve Public Service's initial Stage 1 proposal, including that the potential six percent cost increase would be confirmed by an IA.[51]

44. CEC asserts that the Commission must find a path forward that emphasizes transparency and scrutiny of any further cost increases. CEC does not oppose Public Service's initial proposal for an IA process so long as the IA process "is transparent and the results and IA

[48] Staff's SOP, pp. 3-4.
[49] Staff's SOP, pp. 4-5.
[50] Staff's SOP, pp. 6-7.
[51] UCA's SOP, p. 1.

decisions are subject to stakeholder investigation and challenge…."[52] In contrast, CEC "strongly opposes any proposal that would result in unnecessary and unverified automatic price increases not subject to scrutiny or verification through the IA or a similar process."[53] CEC specifically includes in this opposition proposals to provide uniform cost increases to encourage projects to move forward, especially for those projects that have indicated that no price increase is necessary.[54]

45. CEC reasons that, while the Company's initial proposal is not perfect, the third-party verification provided by the IA provides necessary customer protections and eliminate frivolous or unnecessary price increases.[55] CEC asserts that it is clear from the record that many solar and solar plus storage projects report the ability to execute PPAs at the as-bid PPA rate, assuming they could potentially obtain price relief from future changes of law.[56] CEC acknowledges the timing constraints but maintains the Company and Commission still have a responsibility to protect customers by providing cost increases only for actual and verifiable purposes and not provide unnecessary price increases.[57]

46. More specifically, CEC argues the Commission and Staff should have a role in selecting the IA to ensure that the IA is truly independent from the Company and bidders. In addition, CEC recommends expanding the process for Commission approval of an IA decision. CEC suggests that the 21-day review period be expanded and include an opportunity for intervenor

[52] CEC's SOP, pp. 1-2.
[53] CEC's SOP, p. 2.
[54] CEC's SOP, p. 2.
[55] CEC's SOP, p. 4.
[56] CEC's SOP, p. 4.
[57] CEC's SOP, p. 5.

comment before the Commission must issue a decision to ensure that interested stakeholders have an opportunity to review, audit, and weigh in on any proposed price increase. [58]

### 2. Findings and Conclusions

#### a. PPA Projects

47. The record contains considerable evidence that the current market dynamics and geopolitical environment have evolved since bids were submitted in March 2023 and factors such as supply chain constraints, policy uncertainty, and increased demand for clean energy projects have contributed to upward cost pressures.[59] Moreover, we agree with assertions from parties such as CIEA that further delay may cause additional price increases. We ultimately conclude that some amount of price flexibility is necessary to appropriately balance considerations of reliability, emissions reductions, and ensuring reasonable costs to customers.

48. The Commission agrees with Public Service, Staff, CIEA, COSSA/SEIA, and Interwest that the proposed IA-review process should be rejected for purposes of Component 1, Stage 1. The IA process will almost certainly result in several months of additional delays,[60] and additional delays will likely result in further price increases. Moreover, it is unclear how beneficial an IA would be in balancing the limited increases sought in Component 1, Stage 1 given the complexities of evaluating a variety of projects on an abbreviated basis. The risks that such a process would ultimately result in higher costs and the loss of important clean energy projects outweighs the benefits of a more robust project-by-project review of requested price increases. This is especially true for PPA projects, which do not require a subsequent CPCN proceeding.

[58] CEC's Comments on CEP Delivery, pp. 5-6.
[59] *See, e.g.*, Hr. Ex. 166 (Ihle), pp. 10-24.
[60] COSSA/SEIA's SOP, p. 3.

49. Thus, PPA solar, solar plus storage, and storage projects may receive a maximum price increase of one percent in Stage 1. The PPA wind project may receive up to a six percent price increase. This Stage 1 price relief flexibility for the PPAs is supported by the record evidence including the Company's testimony during the evidentiary hearing and especially the highly confidential updated pricing information contained in Hearing Exhibit 166, Attachment JWI-17, Rev. 1.

50. To receive the Stage 1 price increase, PPA developers must present to Public Service affidavits signed by corporate officers providing narrative descriptions supporting the requested increase and agreeing to the bidirectional nature of Stage 2 and the fact that Stage 1 and Stage 2 relief is considered in the aggregate. In other words, projects that receive a Stage 1 price increase could be subject to a price decrease in Stage 2.[61] Additionally, any Stage 1 price increase counts against the 15 percent cap on price increases possible in Stage 2. Thus, if a project obtains a six percent price increase in Stage 1, it would only be eligible for an additional nine percent price increase based on change of law in Stage 2. Projects that move forward without Stage 1 price relief would still be eligible for Stage 2 price increases but would not be subject to any Stage 2 price decreases. This strikes the balance of allowing bidders to move forward with contracts immediately if they currently have no price increase needs but allows for them to return if there is a change of law that significantly impacts their ability to deliver the project at the bid price. For clarity, and consistent with Staff's position, backup projects may also utilize the Stage 1 price relief mechanism but only after full efforts have been made to move forward with the approved projects and after the approved backup bid selection process is employed.

[61] This is directionally consistent with CIEA's initial proposal in which developers would "agree to the terms of a 'bidirectional' claw back of Stage 1 increases in its PPA, as well as liability for fraudulent statements." (CIEA's Comments, p. 17).

51. We recognize the arguments from CEC, UCA, and Climax that across-the-board price increases risk unnecessarily increasing costs to ratepayers and might constitute an unreasonable windfall for developers at ratepayer expense. However, a lengthy project-specific review might also unnecessarily increase costs through additional delay and threaten the viability of multiple clean energy projects, which could raise additional resource adequacy concerns. The cap on Stage 1 price increases together with the bidirectional nature of Stage 2 and the aggregate 15 percent cap for Stage 1 and Stage 2 price increases help weigh these concerns and reduce the risk that projects will obtain an unnecessary price increase in Stage 1. Further, our decision to defer consideration of the requested price increases for utility-owned projects until the CPCN proceedings as discussed below is consistent with arguments that there must be a project-specific review of each price increase.

**b. Utility-Owned Projects**

52. Given the differences between utility-owned projects and PPA projects, the Commission finds it appropriate to adopt a different Stage 1 approach for utility-owned clean energy projects. Contrary to Public Service's request, we defer granting a presumption of prudence for the proposed price increases or modifying the CtC PIM baselines until the appropriate CPCN proceedings. The Commission and interested stakeholders will be able to evaluate the validity of the requested price increases during the CPCN proceedings in much the same way that Public Service initially anticipated the IA would evaluate price increases. Because Public Service must still obtain CPCNs for the clean energy projects for which it now seeks price relief, withholding approval of the price increases until the CPCN proceedings will not result in any meaningful delay nor the associated concerns about additional price increases and resource adequacy related to further delay, making this distinct from the procedural path for PPA projects.

Moreover, it appears that Public Service is prepared to file CPCN filings for its wind projects in the near future. During the hearing, the Company represented that CPCNs for Bid 1015 and Bid 1024 should be filed about a week after hearing, while the CPCN for Bid 1029 would be filed in early December.[62]

53. Our decision to defer consideration of the requested price increases for utility-owned clean energy projects is similar to the requests of Staff and CEO for the Commission to defer consideration of price increases for the Company's thermal units,[63] and is directionally consistent with Public Service's alternative proposal for those thermal projects.[64] As determined in the respective CPCN proceedings, costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and operational PIM baselines. For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing may potentially constitute extraordinary circumstances within the terms of the CtC PIM (*i.e.*, unforeseen costs that could not have been known at the time the bid was made), subject to future adjudication by the Commission following development of the relevant project. Similarly, although potentially less applicable, the same would be true for the operational PIM. Moreover, prudently incurred costs associated with each of the projects will be eligible for recovery; provided, however, that this in no way impacts the application of the PIMs. For instance, the Company may earn a disincentive under the CtC PIM regardless of whether the underlying costs are imprudent.

54. In addition to the above findings, we clarify that utility-owned clean energy projects are subject to the same price cap as the respective PPA projects. Thus, the Company-owned wind

[62] Hr. Tr. November 7, 2024, pp. 138-39.
[63] Staff's SOP, p. 9; Hr. Ex. 1204 (CEO Response Testimony), pp. 20-21.
[64] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 19.

projects are only eligible for up to a six percent Stage 1 price increase in the CPCN proceedings, consistent with the Company's SOP,[65] and the utility-owned storage project would only be eligible for up to a one percent Stage 1 price increase in the CPCN proceeding. Importantly, this maximum six percent increase and maximum one percent increase shall be applied to the NPV of the respective projects, consistent with the price increases permitted for PPAs, and not on the CtC as the Company requests.

55. On this last point, we find Staff's arguments persuasive. Public Service's proposal to apply the percentage price increase to the project's construction costs for utility-owned clean energy projects but only to the NPV for PPA projects puts utility projects and PPA projects on an unlevel playing field. This unequal treatment could result in utility-owned projects receiving a larger price increase than an otherwise equivalent PPA project.[66] Public Service's own filings demonstrate the issue. A six percent increase on the construction cost of a wind project "translates to a higher percentage increase when compared to the smaller PTC-adjusted cost."[67] More precisely: "the 'six percent of baseline' cost increase divided by a smaller denominator (the PTC cuts approximately half of the cost of the project) ends up at about 12 percent on the PTC-adjusted costs."[68]

56. Public Services raises several arguments against Staff's proposal to limit the percentage price increases to an NPV basis, none of which are persuasive. For instance, the Company argues there are material distinctions between utility-owned and PPA projects and that converting an NPV adjustment to a new CtC baseline is complex.[69] While we agree that material

[65] Public Service's SOP, p. 8.
[66] Hr. Ex. 2709 (Staff Response), p. 20.
[67] Hr. Ex. 166, Attachment JWI-16 (Supplemental Comments), p. 13.
[68] Hr. Ex. 166, Attachment JWI-16 (Supplemental Comments), p. 13.
[69] Hr. Ex. 166, Attachment JWI-19 (Reply Comments), pp. 9-10; Public Service's SOP, p. 7.

differences exist between utility-owned and PPA projects, the Company has not established how any of these differences justify additional price flexibility for utility-owned projects. Public Service knew of these differences and presumable accounted for them when the Company formulated its Phase II bids that now serve as the baseline for the Company's projects. As for the complexity of converting an NPV adjustment to a new CtC baseline, Staff asserts that the Company "grudgingly admits" that it could calculate the NPV for utility projects. According to Staff, all of the necessary information to perform this calculation is contained in the project-by-project updated revenue requirements that Staff obtained in discovery.[70] Moreover, interested parties and the Commission will be able to work through these details in the follow on CPCN proceedings.

57. In its Reply Comments, Public Service makes two alternative requests if the Commission adopts Staff's NPV approach. First, the Company states the NPV approach results in reduced CtC baselines and thus asserts the Commission should modify the methodology used to calculate the incentives and disincentives under the CtC PIM. Specifically, the Company requests the Commission adopt the progressive method as opposed to the landing spot method.[71] Second, the Company argues the Commission should "convert the maximum NPV increase (such as 6%) to a revised CtC for each project, thus setting a new baseline CtC now and avoiding the need for recalculating NPV in the future."[72]

58. We decline to adopt the Company's two alternative requests at this time. Regarding the first request, in the First RRR Decision we rejected the Company's request to switch to the progressive method on the basis that doing so would significantly reduce the level of potential incentives and disincentives under the CtC PIM.[73] In its CEP Delivery Motion filings, the

[70] Staff's SOP, pp. 6-7.
[71] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 11.
[72] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 10.
[73] First RRR Decision, ¶¶ 122-23.

Company does not address this shortcoming with the progressive method. Consistent with our earlier

First RRR Decision, in the CPCN proceedings Public Service may request to implement the progressive method in such a way that is supported and roughly maintains the respective amounts of incentives and disincentives.

59. Similarly, we defer the Company's second request to convert the NPV increase to a revised CtC baseline to the respective CPCN proceedings. In the CPCN proceedings, the Commission and parties can evaluate the actual reasons behind the Company's price increases and the appropriate amount of price relief. The Company's suggestion may be reasonable, but it is unnecessary and premature to rule on the proposal at this time.

### E. Component 1, Stage 2

#### 1. Party Positions

60. As proposed, Stage 2 of Component 1 would allow developers to seek additional price relief based on changes of federal law. The Stage 2 process would be initiated by a motion filed by the Company, Staff, or by the Commission on its own motion, describing the change in law and explaining why Stage 2 relief is appropriate. After considering responses to the motion, the Commission would determine whether to initiate a Stage 2 relief process. After Stage 2 is initiated, any requests for relief must be completed through submittal to the IA no later than December 31, 2025, or 18 months prior to the project's commercial operation date ("COD"), whichever is later.[74] In addition, bidders would be required to submit requests and documentation to the IA within 30 days of any Commission decision approving Stage 2 relief. After the IA makes its verification, it would then submit all materials to the Commission. The Commission would

[74] Hr. Ex. 166 (Ihle), p. 52.

have 21 days to review the IA's verification and, at the Commission's discretion, suspend the requested relief. If the Commission suspended the requested price relief, then there would be a 10-day intervenor comment period, a seven-day Company and bidder response period, and a Commission decision to approve or reject the requested relief within 14 days after the Company response.[75]

61. Stage 2 relief would provide up to a 15 percent total price increase, inclusive of any prior approved increase in Stage 1.[76] Stage 2 is also bidirectional. For example, if PTC/ITC benefits increase, or if current tariffs are repealed, the Company could file for a reduction to the underlying PPA rates (for IPP bids) and CtC PIM baseline costs (for self-build and build-transfer bids).[77]

62. In the event the Commission or the IA rejects all or a portion of a requested and verified Stage 2 increase, a project with an executed PPA would be able to terminate the PPA and receive a 75 percent refund of its Security Fund under Article 11 of the Model PPA if it so elects within 14 days of the Commission decision. Similarly, a build-transfer project could terminate its contract with the Company by paying 25 percent of the Termination Payment.[78] Public Service proposes to implement the Stage 2 process by incorporating the proposed PPA language in Hearing Exhibit 166, Attachment JWI-20.

63. Although Public Service proposes to eliminate the IA in Stage 1, in its SOP the Company continues to support the Stage 2 IA process as initially presented. Public Service reasons that the IA concept "continues to have merit in Component 1, Stage 2, where the time pressures may not be as acute as the current ones and where the required assessments would be more discrete

[75] Hr. Ex. 166 (Ihle), pp. 43, 53.
[76] Hr. Ex. 166 (Ihle), p. 51.
[77] Hr. Ex. 166 (Ihle), p. 51.
[78] Hr. Ex. 166 (Ihle), p. 53-54.

and less subjective."[79] Public Service "requests approval of a Stage 2 process for all PPA and [utility-owned] projects with the same timing and triggers as proposed in the CEP Delivery Plan."[80]

64. In its SOP, Public Service argues the Stage 2 price relief mechanism "would not cover all potential changes in law, such as a full and immediate repeal of the Inflation Reduction Act ("IRA") or repeal of relevant tax credits made available or extended by the IRA."[81] The Company states it is committed to working with developers to address such scenarios, including how posted security is treated under these types of circumstances. In addition, Public Service requests guidance from the Commission as to whether it anticipates using an IA for determining price changes in the event Stage 2 is triggered. The Company asserts an IA could assist the Commission in confirming the project-specific impacts of changes of law in an objective, expedient manner that would significantly reduce the burden on the Commission.[82]

65. In Staff's SOP, Staff largely agrees with the Stage 2 price relief concept. Staff argues that whether Stage 2 price relief is permitted and the level of that price relief should be at the Commission's discretion, up to a maximum of 15 percent inclusive of Stage 1 relief. Consistent with CIEA's initial recommendation, Staff argues that Stage 2 price relief should be bidirectional, except for those projects that agree to go forward with only a one percent increase in Stage 1. For those projects, Stage 2 price relief should only be upward.[83] CEO likewise generally supports the Company's proposed process for Stage 2 pricing relief.[84]

66. In its SOP, CIEA argues for a more generous Stage 2 price relief structure. CIEA reasons the election has changed the calculus regarding the likelihood and scope of potential

[79] Public Service's SOP, p. 6.
[80] Public Service's SOP, p. 14.
[81] Public Service's SOP, p. 14.
[82] Public Service's SOP, p. 16.
[83] Staff's SOP, p. 16.
[84] Hr. Ex. 1204 (CEO Response Testimony), p. 17.

changes of law. According to CIEA, projects that move fast may lock-in existing PTCs, but further delays risk changes of law.[85] While CIEA continues to support the general concept of an IA review of change of law impacts in Stage 2, it argues that several modifications are now necessary. CIEA states it is "imperative" that the Commission allow developers to recover 100 percent of their security payments if projects must withdraw due to a change in law that causes cost increases of over 15 percent for any project. CIEA asserts that if the PTC/ITC is repealed, costs could rise by 100 percent. CIEA similarly argues that even short of a full repeal, partial repeals or changes in tax credit values or tariff amount could all devastate clean energy projects.[86]

67. If the PTC/ITC is repealed or a change in law results in a price increase of more than 15 percent, CIEA also asks that the Commission request full repricing from all CEP projects without the 15 percent Stage 2 limit.[87] CIEA further asks that the Commission extend by one year the December 31, 2025, deadline for bidders to request Stage 2 price relief. CIEA states that changes in law are likely to pass in 2026, so the deadline should be December 31, 2026.[88] CIEA does not oppose the bidirectional nature of Stage 2 but argues developers should be allowed to defend against a downward Stage 2 reduction by showing that their projects did not benefit from a price reduction.[89] Finally, CIEA provides redlined modifications to Public Service's proposed PPA language in Hearing Exhibit 166, Attachment JWI-20. CIEA makes it clear that it "does not request Commission approval of such modified language but provides the redline as an example to demonstrate IPP concerns about potential large, more structural changes of law that now must be taken into account."[90]

[85] CIEA's SOP, pp. 14-15.
[86] CIEA's SOP, p. 16.
[87] CIEA's SOP, p. 5.
[88] CIEA's SOP, pp. 5, 15.
[89] CIEA's SOP, p. 5.
[90] CIEA's SOP, p. 5.

68. In its SOP, COSSA/SEIA strongly supports the Stage 2 price relief for changes in law. COSSA/SEIA further supports retaining an IA to review any requests for Stage 2 price relief, reasoning that "there will be more time for successful bidders to request price relief, for the IA to review the request, and for the Commission to approve that price relief."[91] Nevertheless, COSSA/SEIA does request changes to the Stage 2 process. COSSA/SEIA asks for an appeals process in which a developer could request Commission review of a price increase that is denied by the IA. COSSA/SEIA asserts the appeal should take place in a separate Commission proceeding so that individual developers could seek Commission review of an unfavorable IA decision.[92] COSSA/SEIA also argues against the PPA language Public Service proposes in Attachment JWI-20. COSSA/SEIA asserts the Company's current language forces developers to bear all the risk, including losing their security deposit, if the IA or the Commission denies the requested price relief. COSSA/SEIA does not propose specific changes but asks that the Commission "adopt language that directs the Company to renegotiate bid security terms in any situation where Stage 2 price relief is denied by the Commission."[93]

69. More generally regarding PPA provisions, COSSA/SEIA argues the Commission "should refrain from making any determinations regarding the reasonableness or acceptability of any particular PPA provision."[94] COSSA/SEIA particularly cautions against any Commission finding related to the security provisions in Hearing Exhibit 166, Attachment JWI-21. COSSA/SEIA argues that PPA terms cannot be viewed in isolation but must be seen in the context of the larger give-and-take negotiation.[95]

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[91] COSSA/SEIA's SOP, pp. 3-4.
[92] COSSA/SEIA's SOP, p. 4.
[93] COSSA/SEIA's SOP, p. 4.
[94] COSSA/SEIA's SOP, p. 6.
[95] COSSA/SEIA's SOP, p. 5.

70. Interwest argues that quick decision making and a fair and robust opportunity for project developer level input is critical if there are any future changes in law or tariff.[96]

71. In its SOP, UCA recommends the Commission approve the Company's plan for a potential 15 percent price increase in Stage 2.[97] UCA opposes, however, the Company's proposal to partially refund security deposits or other walk-away provisions. UCA reasons that security deposits provide a substantial incentive for developers to go forward with their projects or to minimize the requested price increase. UCA argues that developers knew their security deposits were at risk when they submitted their bids, and the security deposits should not be reduced or lost.[98]

### 2. Findings and Conclusions

72. The general concept of a Stage 2 process to addresses changes in law has widespread party support and appears to be critical for most, if not all, of the clean energy projects.[99] The Company's proposed Stage 2 process is a useful structure that will encourage developers to move forward with projects even though future tariffs or changes to tax credits might impact the projects' financials. Therefore, the Commission adopts the Company's proposed Stage 2 process for both PPA and utility-owned projects, subject to the below modifications and clarifications.

73. Although a project-specific IA review in Stage 1 is inappropriate for the reasons discussed above, we agree with several of the parties that an IA review in Stage 2 appears useful and efficient. We find persuasive the Company's arguments that an IA review has merit in Stage 2, "where the time pressures may not be as acute as the current ones and where the required

[96] Interwest's SOP, p. 3.
[97] UCA's SOP, p. 9.
[98] Hr. Ex. 509 (UCA Testimony), pp. 26-27.
[99] Hr. Ex. 166, Attachment JWI-17, Rev. 1.

assessments would be more discrete and less subjective."[100] Consistent with the Company's request in its SOP for more guidance regarding the role of the IA, we clarify that the IA will ideally provide independent analysis of the documentation provided by the various developers and will produce initial determinations as to whether price modifications are appropriate. The methodology underlying these determinations should be consistent across all relevant projects, regardless of technology or ownership type.

74. To ensure the IA is ready and available if and when needed, Public Service shall confer with Staff and UCA on the selection of an IA and development of a scope of work. The Company must submit a motion to approve the proposed IA together with an IA scope of work no later than March 31, 2025. Public Service's proposal to defer costs associated with the IA and recover them through the ECA seems reasonable, but Public Service must set forth the specifics of its proposed cost recovery mechanism in the March 31, 2025 motion. Parties to this Proceeding would have 14 days to file any responses to the Motion. Establishing this process at the outset will hopefully save time if and when Stage 2 is triggered.

75. Consistent with CEC's arguments for additional transparency, the Commission finds that certain modifications to the proposed IA review process are necessary. First, intervenors should have an opportunity to review and comment on the IA's Stage 2 determinations prior to a Commission decision. Intervenors shall have 21 days to review the IA's initial determination. Public Service and any impacted developer would then have seven days to file response comments. The IA's determination would not go into effect until the Commission decision, which would be issued in due course.

[100] Public Service's SOP, p. 6.

76. We generally agree with the Company that any requests for Stage 2 relief should be submitted to the IA no later than December 31, 2025, or 18 months prior to the project's COD. We empathize, however, with concerns from CIEA that changes in law might occur in 2026. Thus, while we adopt the Company's proposed deadline at this time, parties may petition for an extension as necessary.

77. Consistent with our discussion above, we emphasize that the Stage 2 process is bidirectional for any projects that received Stage 1 price relief. Projects that did not pursue and receive Stage 1 price relief are still eligible for Stage 2 relief, but only in the upward direction.[101] We agree with CIEA that pricing relief obtained in Stage 1 would be "[s]ubject to downward adjustment in Stage 2."[102] We further agree with CIEA, however, that developers are permitted to argue via the established Stage 2 process that their projects should not be subject to a price reduction.

78. We recognize the importance of clarifying the consequences if a developer does not obtain the requested Stage 2 relief or if such relief is insufficient to address the change in law. The Commission adopts the Company's initial approach in which developers could terminate the PPA/build-transfer agreement if their Stage 2 price relief was denied and only pay 25 percent of the security deposit/termination payment, so long as the developer elects to do so within 14 days of the Commission decision. Adopting the contrary approach supported by CIEA and COSSA/SEIA and allowing developers to terminate their contracts with no financial consequences if any portion of their Stage 2 request is denied would incentivize all developers to request the full 15 percent price relief and would put significant pressure on the IA and Commission to approve

[101] Public Service's SOP, p. 15.
[102] CIEA's SOP, p. 6; *see also*, CIEA's Comments, p. 17.

the Stage 2 requests without modification. In contrast, requiring developers to pay at least 25 percent of the security deposit/termination payment incentivizes developers to move forward with the projects at or below the 15 percent price cap. PPA provisions that allow bidders to renegotiate bid security terms or walk away with more than 75 percent of the security deposit/termination payment if any portion of a bidder's Stage 2 request is denied would be contrary to this Decision.

79. While the Commission empathizes with UCA's request that developers be required to pay 100 percent of their security deposit if they withdraw, the Company's 25 percent threshold is a more balanced approach. UCA's request ignores the substantial uncertainty that future changes in law pose to CEP projects. Allowing developers to recover 75 percent of their security deposit/termination payment will encourage serious projects to execute PPAs/build-transfer agreements, despite the uncertain future.

80. A related issue is CIEA's argument that developers be allowed to recover 100 percent of their security payments if projects must withdraw due to a change in law that causes cost increases of over 15 percent for any project. In the event there is an established change of law that exceeds the 15 percent cap, we agree that developers should be allowed to terminate their PPAs and recover 100 percent of their security payments. Allowing this type of flexibility in the event of a significant change in federal law will again encourage developers to execute PPAs and attempt to develop their projects. To be clear, this full return of the security payment would not be allowed whenever a developer claims that a change in law increased prices by more than 15 percent. Rather, this option would only be available after a developer establishes to the

Commission's satisfaction that a project experienced a legitimate price increase of more than 15 percent and this price increase is directly caused by a change in law.[103]

81. We decline from approving at this time CIEA's request that the Commission request repricing from all CEP projects without the 15 percent Stage 2 cap if there is a significant change in federal law. At some point, the Commission may be better off allowing impacted CEP projects to fail and relying on the JTS to reestablish the market price for clean energy projects.

82. Finally, we find COSSA/SEIA's request to establish a separate appeals process for bidders to be unnecessary and duplicative of existing avenues. Under the Stage 2 process established above, bidders already have an opportunity to provide input in the seven-day response period.[104] With the established Stage 2 IA process and the Commission's existing provisions for third parties to file a complaint to initiate a new proceeding, we do not see the need to create an additional appeals process per COSSA/SEIA's request.

### F. Other Component 1 Issues

#### 1. Selection of Additional Solar and Solar Plus Storage Bids

83. In addition to its other arguments regarding Component 1, UCA argues the Commission should consider selecting additional solar and solar plus storage bids. UCA asserts the large increase in future capacity need shown in the Company's initial JTS filings in Proceeding No. 24A-0442E supports taking additional capacity in this Proceeding.[105] UCA recommends the Company investigate whether the lowest-cost solar and solar plus storage projects are able to go

[103] For purposes of determining whether a project can recover 100 percent of its security deposit, the 15 percent threshold is based on the project's initial as-bid price, even if a project obtains a price increase in Stage 1. For instance, if a project received a six percent price increase in Stage 1, the developer would still be required to show more than a 15 percent price increase due to a change of law—even though the project would only be eligible for a nine percent price increase in Stage 2.

[104] *Supra* ¶ 75.

[105] UCA's SOP, pp. 4-5.

ahead under the proposed price increases proposed in Component 1. UCA specifically focuses on Bids 0718, 0649 and 0651 (all solar projects) and Bid 0567 (a solar plus storage).[106]

84. The Commission denies UCA's requests to investigate whether additional solar and solar plus storage projects can move forward under the Component 1 price relief mechanism. It is far from clear on this record that the additional bids UCA flags could move forward under Component 1 or that there should be a presumption of prudence for their acquisition. For instance, it is uncertain whether the interconnections for these new projects could be timely achieved. While we ultimately deny UCA's recommendation, we note that Public Service could always seek authorization to pursue such additional projects outside of the JTS Proceeding, especially if the Company sees a potential cost-savings or reliability benefit.

### 2. Presumption of Prudence for Incremental Cost Increases

85. CEC raises the additional argument that any incremental cost increase in Component 1 should not be afforded the presumption of prudence per Rule 3617(d). CEC reasons the proposed Component 1 cost increases "would occur outside of the Commission's competitive solicitation rules" and thus any approved cost increases should be subject to prudence challenges.[107] CEC further argues that escalating CEP costs were foreseeable and predicted by the Independent Evaluator Report.

86. We reject CEC's argument regarding the application of Rule 3617(d). Given the competitive bidding process underlying the initial selection of these bids, the evidence put forth regarding the need for price increases, and the process and protections inherent in the Stage 1-Stage 2 mechanisms, price increases awarded under Component 1 will carry a presumption of prudence

[106] UCA's SOP, p. 6.
[107] CEC's SOP, p. 3.

per Rule 3617(d). This will help provide Public Service the regulatory certainty it needs to quickly pursue these clean energy projects and avoid future delays and cost increases.

### G. PPA Execution and Requests for Rule Variances

#### 1. Party Positions

87. In its CEP Delivery Motion, Public Service seeks variances from Rule 3613(i) and Rule 3613(j). Under Rule 3613(i), a utility must execute contracts for resources within 18 months after the utility's receipt of bids to receive the presumption of prudence per Rule 3617(d). This deadline was September 1, 2024. Public Service seeks a six-month extension so that the new regulatory deadline to execute contracts is March 1, 2025. [108] Under Rule 3613(j), a utility must file a proposal within 14 months after the receipt of bids that addresses the public release of all confidential and highly confidential information related to bids. The deadline for this filing was May 1, 2024. Public Service proposes to extend this deadline by at least 11 months to April 1, 2025. Public Service states that the bids are in a very sensitive state and may change based on the relief contemplated in the CEP Delivery Motion.[109]

88. CIEA, COSSA/SEIA, and Interwest all argue the Commission should act to prevent further delays in executing PPAs. CIEA asserts Public Service's delay in PPA executions is a contributing factor for the need for price increases and that Public Service appears to be "understaffed and overwhelmed."[110] In its Response Comments, Interwest states that "timeliness" is the most critical factor in achieving the goals of the CEP and that the available time to complete

[108] CEP Delivery Motion, p. 14.
[109] CEP Delivery Motion, p. 15.
[110] CIEA's CEP Delivery Comments, p. 20.

projects and meet CODs is becoming prohibitively short.[111] Interwest further asserts there have been significant delays during contract negotiations due to the Company's own action.[112]

89. To prioritize PPA execution going forward, CIEA recommends the Commission require Public Service to submit by December 31, 2024, a filing updating the Commission on all PPA negotiations, and every month thereafter. CIEA also suggests the Commission direct the Company to prioritize quicker PPA execution over holding the line on withdrawal "outs" and penalties for IPPs. That said, CIEA expressly asks that the Commission take no action on the specific terms of PPAs presented by Public Service at this time.[113]

90. COSSA/SEIA critiques the Company's requested variance of Rule 3613(i) in the context of delayed PPA execution. COSSA/SEIA argues that Rule 3613(i) puts pressure on the Company to execute PPA and build-transfer contracts swiftly. According to COSSA/SEIA, granting the Company's requested variance would reward "the bad behavior and foot-dragging that occurred from the Company not executing contracts in a timely manner."[114] COSSA/SEIA recommends the Commission deny the requested variance and reserve its decision to grant or deny the presumption of prudence until after the CEP Delivery bids are finalized.[115] In the alternative, COSSA/SEIA argues that if the Commission grants the variance, the revised deadline for compliance should be as short as possible and a firm deadline that is not subject to additional delays. COSSA/SEIA suggests the extended deadline should be December 31, 2024. COSSA/SEIA also asks that the Commission confirm that bid prices will become public on that date.[116]

[111] Interwest's Comments, pp. 2-3.
[112] Interwest's Comments, p. 6.
[113] CIEA's SOP, p. 7.
[114] COSSA/SEIA's SOP, p. 9.
[115] COSSA/SEIA's SOP, p. 9.
[116] COSSA/SEIA's SOP, pp. 9, 12.

91. In its Reply Comments, Public Service asserts it is negotiating in good faith with all bidders and warns the Commission against relying on the unattributed statements from COSSA/SEIA and CIEA. Public Service asserts several PPA are in near-final draft form and that this demonstrates the Company's ability to reasonably negotiate with IPPs. For other bids, Public Service says there are issues outside of the Company's control, such as a developer's need for price relief or insistence on receiving a Component 1, Stage 2 relief mechanism.[117] The Company states that negotiations of long-term, multi-million-dollar contracts are always challenging and that while it agrees on the importance of executing PPAs, the timeframe for these negotiations is not atypical.[118] The Company asserts that no IPP developers were able to execute a PPA given the need for either direct pricing relief or assurances of relief in the event of future changes in tariffs or the availability of tax credits.

92. Ultimately, Public Service proposes to submit monthly reports, beginning in January 2025, on the status of negotiations for all PPA and IPP build-transfer projects. The Company states that these reports will be similar in form to Table 1 in the Company's October 4 Supplemental Filing, Hearing Exhibit 166, Attachment JWI-16HC. The Company commits to continue this monthly reporting until all PPAs for the CEP are executed.[119]

### 2. Findings and Conclusions

93. The Commission agrees that timeliness is a critical factor for the CEP's success. Indeed, this urgency is one of the main factors supporting our decision to eliminate the IA process in Stage 1 of Component 1 for PPA projects. Our decisions providing bidders and the Company

[117] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 30.
[118] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 28; Public Service's SOP, pp. 16-17.
[119] Public Service's SOP, p. 17.

more certainty regarding Component 1 price relief processes and the extent to which bidders can recover their security deposit should also help accelerate the negotiation process.

94. Nevertheless, the Commission denies CIEA's suggestion to direct Public Service to prioritize quicker PPA negotiations over penalties if IPPs walk away from the PPA. Apart from our earlier decisions regarding the recovery of security deposits, we see little value in issuing vague directives to focus on executing PPAs at the expense of other contested terms. As to CIEA's request that the Commission take no action on specific PPA terms, we agree that there is no need for the Commission to approve specific PPA provisions at this time.

95. Regarding CIEA's request for monthly updates from Public Service on all PPA negotiations, it appears that Public Service largely agrees with this concept. Consistent with the proposals from CIEA and Public Service, we direct the Company to submit monthly reports in this Proceeding on the status of negotiations for all PPA and IPP build-transfer projects. These negotiation reports shall be due on the fifth of every month,[120] and will continue until all PPAs and build-transfer agreements for the CEP are executed. Public Service shall confer with the individual bidders on the negotiation status that the Company intends to provide in the negotiation report. Conferral confirmation must be provided in the report to the Commission.

96. Turning to COSSA/SEIA's opposition to the Company's requested variance of Rule 3613(i), we agree that Rule 3613(i) ideally should incentivize Public Service to execute PPAs swiftly. We disagree, however, with COSSA/SEIA's primary recommendation to deny the variance and defer granting a presumption of prudence until after bids are finalized. Removing regulatory certainty in this way might cause additional delays. COSSA/SEIA's alternative

[120] The first report requirement shall commence the fifth of each month following issuance of this Decision, with an initial report for January of 2025 provided as soon as practicable following issuance of this Decision.

recommendation of a December 31, 2024 deadline is not feasible. Therefore, we grant the Company's requested variance and adopt the March 1, 2025 deadline the Company proposes in the CEP Delivery Motion. We clarify, however, that any request to extend the March 1 deadline must be accompanied with a detailed description of Public Service's efforts specific to each individual PPA and build-transfer agreement. Similar to the monthly negotiation reports but with more detail, Public Service shall confer with the individual bidders on the information the Company intends to provide regarding efforts to finalize PPAs, and conferral confirmation must be included.

97. We also grant Public Service's variance from Rule 3613(j) regarding the public release of bid information. We agree with the Company that the bids are in a "sensitive state" and it is too soon to publicly release confidential information regarding such as bid prices. The April 1, 2025 deadline is a reasonable amount of time for Public Service to submit a proposal for the public release of such information.

**H. JTS Proceeding**

**1. Party Positions**

98. Several parties recommend the Commission take certain actions regarding the ongoing JTS Proceeding in light of the challenges presented in the CEP Delivery Motion. For instance, Staff argues that in the JTS Proceeding, the Commission should consider consequences for bids that have failed in this process from reappearing in the JTS Proceeding. Such consequences could include higher bid fees or stricter walkaway provisions.[121] Staff suggests the Commission consider consequences for bids that have failed in this process that reappear in the JTS Proceeding (*e.g.*, higher bid fees or stricter walkaway provisions). Staff does not

[121] Staff's SOP, p. 17.

recommend setting such consequences here but encourages the Commission to inform bidders that withdrawing an approved bid submitted in this ERP only to re-bid the same project in the JTS Proceeding may result in heightened review or financial scrutiny.[122] CEO similarly suggests that bids that receive Component 1 price relief only to pull out of this process and bid into the JTS Proceeding could be subject to higher bid security fees, stricter walk-away provisions, or other measures that will increase the surety of future contracts.[123]

99. UCA opines that the Company and the Commission have been lax in ensuring that IPPs are not advantaging Colorado's ERP system. UCA recommends that any projects that pull out of this Proceeding from this point forward be ineligible to bid in the JTS Proceeding.[124]

100. COSSA/SEIA and CIEA make sweeping suggestions for how to reform the JTS Proceeding. For instance, COSSA/SEIA suggests setting a deadline in the JTS Proceeding for the expiration of bid pricing after which bidders would be allowed to refresh pricing.[125] One of CIEA's suggestions is for the Commission to consider a "best and final" pricing opportunity in the JTS Proceeding for IPPs to sharpen their pencils and adjust pricing after the levelized cost screening.[126]

101. Interwest states that the extended timelines in the Proceeding are putting investment at risk. Interwest warns that if development risks in Colorado are not reduced in future solicitations by trimming delays "the state may risk losing its appeal as a key focus for renewable project development."[127] According to Interwest, it is critical for the Commission to be able to fully investigate the Company's management of the CEP resource solicitation such that the problems in this Proceeding are not repeated in the JTS Proceeding and that "[the Company's] rhetoric be

[122] Hr. Ex. 2709 (Staff Response), p. 26.
[123] Hr. Ex. 1204 (CEO Response Testimony), p. 16.
[124] Hr. Ex. 509 (UCA Testimony), p. 11.
[125] Hr. Ex. 2202 (COSSA/SEIA Response Testimony), pp. 34-36.
[126] CIEA's Response Comments, pp. 26-27.
[127] Interwest's Comments, p. 3.

reviewed through a factual lens."[128] Interwest accordingly requests that the Commission make numerous changes to the JTS Proceeding. For instance, Interwest ask that Public Service be required to submit a separate filing in its JTS Proceeding with an analysis of every point in the CEP where any delay could have been avoided and suggestions for preventing similar delays in the JTS Proceeding.[129] Interwest also recommends the Commission require Public Service to include a bid price expiration deadline and to develop a PIM that would reward Public Service for conducting timely portfolio reviews and executing contracts efficiently.[130]

### 2. Findings and Conclusions

102. We reject the various suggestions to use this Proceeding to set new requirements for the currently ongoing JTS Proceeding. The intervenors in the JTS Proceeding are welcome to propose modifications in that proceeding, where they can be adjudicated by all parties in the JTS Proceeding.

103. We similarly deny suggestions from Staff, CEO, and UCA that there should be some type of predetermined consequence in the JTS Proceeding if a bidder abandons a project that was proposed in this Proceeding given all the difficulties, delays, and challenges that have occurred. That said, parties in the JTS Proceeding are free to argue that a particular bidder or a bidder's pricing is unreliable because of past actions. The Commission will consider such arguments as they come before us, but we decline from using this Proceeding to decide how bidders in the JTS Proceeding will be evaluated.

[128] Interwest's Comments, pp. 3-4.
[129] Interwest's Comments, p. 7.
[130] Interwest's Comments, pp. 8-9.

### I. Replacement for Bid 0235

#### 1. Party Positions

104. In the CEP Delivery Motion, Public Service seeks authorization to replace Bid 0235 (a 219 MW new-build PPA thermal resource that was included in the approved resource portfolio but is no longer available) with Bid 1000 (a Company-owned thermal resource). The Company separately seeks authorization to extend the PPA for Plains End (an existing 219 MW PPA thermal resource) to add additional capacity to its system.[131] Public Service argues the additional capacity it seeks in the CEP Delivery Motion is reasonable given the already tight summer capacity positions the Company is facing. The Company further reveals it has updated its methodologies for the planning reserve margin ("PRM") and effective load carrying capability ("ELCC") values and is developing a new base load forecast in advance of the JTS. Based on these new assumptions, the Company asserts it is facing real and substantial capacity needs in the coming years.[132]

105. CEO opposes the Company's proposal and recommends the Commission approve the Plains End PPA extension as the replacement for PPA Bid 0235. CEO notes that in the Phase II Decision, the Commission approved 669 MW of nameplate thermal capacity via Bids 0989, 0997, 0011, and 0235. Public Service now asks that the Commission approve 869 MW of nameplate thermal capacity via Bids 0989, 0011, and 1000, and by extending the Plains End PPA contract.[133] CEO argues that the Company does not need to secure an additional 200 MW of capacity at this time.[134] CEO asserts that the Commission's decision should be based on the facts that have been litigated in the instant proceeding.[135]

[131] CEP Delivery Motion, p. 9.
[132] Hr. Ex. 166 (Ihle), pp. 106-10.
[133] Hr. Ex. 1204 (CEO Response Testimony), pp. 21-22.
[134] Hr. Ex. 1204 (CEO Response Testimony), p. 22.
[135] Hr. Ex. 1204 (CEO Response Testimony), pp. 26-27.

106. WRA similarly recommends that the Commission approve the Plains End PPA extension as a replacement for Bid 0235 instead of Bid 1000.[136] WRA raises significant concerns about the Company's thermal proposals but notes that due to the nature of this filing and associated procedural schedule, the Commission and parties are unable to effectively investigate the Company's claims regarding resource adequacy issues. According to WRA, there are significant differences in the Company's capacity position if it is viewed through the lens of the currently approved ELCC and PRM conventions, as compared to the Company's new and unvetted methodologies.[137] WRA characterizes the issues as follows: "should the Commission approve the acquisition of additional thermal capacity to address resource adequacy concerns outside the RAP of this proceeding, that are based on ELCC and PRM methodologies that have not yet been litigated."[138]

107. WRA argues that with the updated ELCC/PRM methodologies, Public Service is attempting to justify its proposal to extend the Plains End PPA and pursue a larger self-build thermal bid. WRA observes that one factor influencing the capacity position shortage under updated methodologies appears to be the updated treatment of DR resources. Under current conventions, where DR is treated as a load reduction, DR contributes between 651 MW to 787 MW of load reduction, depending on the year. Under the Company's new methodologies, however, DR is included in the generation category, with capacities ranging from 335 MW to 372 MW. WRA reiterates its claim that the Commission and parties have extremely limited evidence about the factors driving the Company's resource adequacy claims and how these factors manifest in the loads and resources table.[139]

[136] WRA Comments on CEP Delivery, pp. 8-9.
[137] WRA Comments on CEP Delivery, p. 10.
[138] WRA's SOP, pp. 2-3.
[139] WRA Comments on CEP Delivery, p. 14.

108. Staff is more deferential to the Company's obligation to evaluate the reliability of its generating portfolio but ultimately notes the same issues that CEO and WRA raise. In its Response Testimony, Staff acknowledges that the Company retains the obligation to evaluate the reliability of its generating portfolio but states that Staff struggles to see the need for additional thermal capacity in 2028. Staff implores the Company to provide a robust discussion of this issue in its responsive comments and asserts that, without such complete explanation, Staff will not support the acquisition of an additional 200 MW of thermal generation.[140] Conversely, Staff states it will support the Company's position if it can fully demonstrate and explain the reliability concern necessitating the acquisition of the additional 200 MW of thermal capacity.

109. In its SOP, Staff references the load and resources ("L&R") table from Volume 2 of the JTS that Public Service provides in its Reply Comments (JTS Table 2.9-1) as illustrating a significant capacity shortfall through 2033 (e.g., 646 MW in 2025 and 534 MW in 2026). Staff moreover asserts that this L&R Table underestimates the capacity shortfall in that some of the assumed CODs have been pushed back and a solar bid has failed.[141] Nevertheless, Staff stops short of endorsing the Company's proposal.

110. If the Commission determines that the Company has not provided sufficient support for its reliability concerns, Staff states there are two options. First, the Commission could retain the two thermal projects currently in the approved resource portfolio (Bid Nos. 0989 and 0997) and simply add Plains End. Second, the Commission could replace both Bid 0989 and 0997 with Bid 1000 as well as Plains End. Staff's preference is the second option, given that Bid 1000 appears more economical than Bid 0989.[142]

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[140] Hr. Ex. 2709 (Staff Response), p. 35.
[141] Staff's SOP, p. 15.
[142] Staff's SOP, p. 15.

111. In its Reply Comments, Public Service asserts that using the Plains End PPA extension as the replacement for Bid 0235 is untenable. Public Service proffers two arguments in support of is position. First, the Company asserts that replacing a new-build thermal asset with the existing Plains End unit does not work from a reliability perspective. Second, the Company argues that forgoing new thermal capacity now is not an option given anticipated resource needs.[143] More bluntly, Public Service states that "[t]he Company will not sign the [Plains End] extension if doing so is conditioned on removing Bid 1000—the best available option to replace Bid 0235—from the portfolio, as some intervenors suggest."[144]

112. Regarding the need for a new-build combustion turbine ("CT") from a reliability perspective, Public Service asserts that it undertook the alternatives analysis the Commission required in its First RRR Decision for the replacement of Bid 0235 and that the preferred result is acquiring Bid 1000 as the replacement for Bid 0235. "Public Service strongly believes that a full portfolio of *new* thermal assets, i.e., at or near 669 MW, is required to continue the energy transition in a reliable manner."[145] The Company asserts an extension of the Plains End unit, which is 20 years old, "is not a substitute for a new CT unit, which the Commission has already approved."[146] Public Service further alleges that "[t]he approval of the acquisition of three new CTs in the Phase II Decision to meet reliability needs is a closed issue," noting that "[n]o party challenged this need on [RRR]."[147] The Company references the Phase II Decision in which the Commission stated that it "cannot simply carve out from a modeled resource portfolio some or all of the firm dispatchable resources that Public Service maintains are necessary for reliability."[148]

[143] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 17-18.
[144] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 26.
[145] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18 (emphasis in original).
[146] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 21.
[147] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[148] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 24-25 (quoting Phase II Decision, ¶ 125).

Similarly, Public Services references its earlier arguments in its Response Comments to the 120-Day Report when it stated that "eliminating gas units or taking the shortcut of substituting suboptimal and questionable short-term PPA extensions . . . makes the plan less reliable and risks reliability."[149]

113. On the other hand, Public Service emphasizes that it is not arguing against the Plains End PPA extension. The Company states that Plains End is valuable to the Company from capacity, black start, and transmission support perspectives.[150]

114. As to its argument that foregoing additional thermal capacity is not an option, Public Service argues that a five-year extension of Plains Ends is temporary and creates a hole that will need to be filled when the PPA expires. The Company asserts that it cannot count on any capacity from Plains End after the five-year extension expires, making the PPA extension "an inferior option from a reliability perspective."[151]

115. Referencing its direct case in the JTS Proceeding, Public Service asserts that it has substantial and growing capacity needs due to projected load growth and its revised ELCC and PRM studies.[152] Public Service acknowledges interveners' concerns that the JTS L&R table has not been litigated. Public Service argues, however, that "the appropriate question is not whether the updated load forecasts and ELCC and PRM studies have been approved, but whether it represents the best information available to the Company when making choices in a challenging environment."[153] Referencing the recently-filed JTS Proceeding, the Company states it is "confident of substantial needs for new generation—including both new renewable generation and

[149] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 26 (quoting Public Service's Response Comments to the 120-Day Report, pp. 28-29).
[150] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 26-27.
[151] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[152] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 27.
[153] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 27.

new firm dispatchable generation—above and beyond anything we have seen in Colorado."[154] Based on this new modeling, Public Service argues that it is prudent to approve the Company's Component 2 portfolio and to extend the Plains End PPA to meet demand in a dynamic environment. Conversely, the Company argues it would be imprudent to simply ignore the best-available information and hope that capacity needs will remain flat.[155]

116. In its SOP, Public Service maintains its position, arguing that it has performed an analysis of all available thermal alternatives and "the Commission has approved the need to build a total of three new [CT] units" in addition to a thermal project in the San Luis Valley.[156] Public Service also states that "Plains End is not a substitute for the new thermal capacity the Commission approved in Phase II."[157]

**2. Findings and Conclusions**

117. As presented through this CEP Delivery Motion process, Public Service has failed to meet its burden of proof that Bid 1000 is the appropriate replacement for Bid 0235. We therefore deny applying the ERP presumption of prudence under Rule 3617(d) to the Company's proposed replacement for Bid 0235. Instead, the presumption of prudence is limited to the combination of the Plains End PPA extension, Bid 0011, and *either* Bid 1000 or Bid 989 (discussed further below). If the Company insists that the extension of the Plains End PPA, Bid 0011, Bid 0989, *and* Bid 1000 are all necessary for reliability, it can proceed with that option and retain its burden to show in subsequent proceedings the prudency for the incremental thermal capacity (*i.e.*, Bid 1000 or Bid 989) and any associated costs.

[154] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18.
[155] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 28.
[156] Public Service's SOP, p. 9.
[157] Public Service's SOP, p. 11.

118. The arguments Public Service puts forth for why the Plains End PPA extension cannot be used to replace Bid 0235 are unpersuasive. Starting with the Company's assertions regarding reliability of Plains End compared to a new-build thermal resource, we note the Company raises no concerns with the location of the Plains End unit compared to the Bid 0235 nor points to any known reliability issues with Plains End. Indeed, Public Service states that the Plains End PPA extension "is valuable to the Company from capacity, black start, and transmission support perspectives…."[158] Instead of raising specific reliability concerns with Plains End, Public Service seems to argue that anything less than three *new* CTs is per se unreliable. For instance, the Company asserts that "[t]he approval of the acquisition of three new CTs in the Phase II Decision to meet reliability needs is a closed issue,"[159] and that "Plains End is not a substitute for the new thermal capacity the Commission approved in Phase II."[160] These statements imply that the Commission found in the Phase II Decision that approximately 650 MW of *new-build* thermal resources is necessary for reliability.

119. We disagree with the Company's characterization of our findings regarding new-build thermal resources. While the thermal resources within the approved portfolio were admittedly all new builds, for reasons unknown to the Commission, the Company did not identify the potential to extend the Plains End PPA as an option until the CEP Delivery Motion. Public Service cannot now argue that failure to include such PPA extensions in the approved portfolio is a finding that such resources are inappropriate. Indeed, existing PPA units *were* included in the approved backup thermal portfolio, and Public Service never contested that these approved backup resources could not replace a new-build resource. In fact, in the First RRR

[158] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 26-27.
[159] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[160] Public Service's SOP, p. 11.

Decision we rejected Public Service's request to replace Bid 0235 with Bid 1000 because there was no analysis as to whether the existing PPA units such as Bid 1061, Bid 0510, and Bid 0514 could serve as the replacement.[161] Public Service never sought RRR on this point.

120. Contrary to the Company's assertion that the existing Plains End unit cannot be a substitute for the new-build thermal resources initially in the approved portfolio, we see existing PPA units such as Plains End as providing valuable ownership diversity and protection from additional costs. In our Phase II Decision, we noted that Company-owned thermal resources subject ratepayers to the risk of construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded. We found the approved resource portfolio more desirable than the Company's preferred portfolio in part because the approved portfolio contained a PPA thermal resources, which "reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources."[162]

121. The Company's second argument regarding growing resource adequacy concerns is also unconvincing. We acknowledge the Company's new L&R Table put forth in the JTS shows significant capacity shortfalls through 2033. Ultimately, however, we agree with CEO and WRA that our decisions regarding resource adequacy should be grounded in the evidence that has been litigated in this Proceeding. The resource need projections on which the Phase II Decision relies have been thoroughly vetted throughout this long Proceeding. We are disinclined from adopting the Company's eleventh-hour change in its resource adequacy forecasts as a justification to acquire an additional 200 MW of thermal resources.

[161] First RRR Decision, ¶¶ 77-78.
[162] Phase II Decision, ¶ 108.

122. To be clear, we are not prohibiting the Company from moving forward with the requested incremental thermal resources. We simply conclude that Public Service has not earned a presumption of prudence in this Proceeding, particularly based on the relatively truncated and late-stage process associated with the CEP Delivery Motion. If the Company is convinced it needs additional thermal resources above those approved in this ERP Proceeding, it has other methods of obtaining regulatory certainty before construction, including through a CPCN proceeding. Public Service is ultimately responsible for ensuring reliability. In this vein, we encourage Public Service to continue moving forward with actions it reasonably believes are necessary to ensure the Company has the resources it needs to ensure reliability. This may include, for example, development and permitting work associated with all of its proposed thermal resources.

123. As for the thermal resources for which the Company does enjoy a presumption of prudence, we ultimately provide the Company discretion to pursue either of the two options put forth by Staff. In Option 1, Public Service would enjoy a presumption of prudence for the following thermal resources: the Plains End PPA extension, Bid 0989, Bid 0997, and Bid 0011. In Option 2, Public Service would enjoy a presumption of prudence for the following thermal resources: the Plains End PPA extension, Bid 1000, and Bid 0011.[163]

124. We agree with Staff that Option 2 appears more attractive given the cost advantages of Bid 1000. Moreover, Option 2 avoids the complexities associated with Bid 0989 as discussed below. Nevertheless, we acknowledge there are additional factors that might impact the appropriateness of the two options, such as the timing of when various resources can come online

[163] If, for example, the Company decides to move forward with the Plains End PPA extension, Bid 1000, Bid 0011, *and* Bid 0989, then Bid 0989 would be incremental to Option 2 and thus would not enjoy a presumption of prudence. The other thermal resources would enjoy a presumption of prudence.

and the locational differences of the various resources. Based on the record before us, Public Service is in the best position to determine which option is preferable.

### J. Thermal Resource Price Increases

#### 1. Party Positions

125. As part of the CEP Delivery Motion, Public Service seeks the ERP presumption of prudence per Rule 3617(d) that pursuit of the thermal units at the new revised cost levels is prudent. In addition, Public Service asks that the CtC PIM baseline for the utility-owned thermal facilities be adjusted upward to match the new cost estimates.[164]

126. Several intervenors disagree with the Company's request regarding the proposed price increases of the thermal units. For instance, Staff recommends that the Commission not grant the Company the specific price relief, arguing there is simply not enough time and information to ascertain whether the requested relief is reasonable.[165] Staff's strong preference would be for the Company to present its financial analysis in the CPCN proceedings to appropriately allow parties time to examine the Company's estimates, changed circumstances, financial accounting, *etc*. Such CPCN proceedings could appropriately re-establish the individual CtC baselines after careful consideration of the detailed information.[166]

127. In its SOP, Staff argues that the "the Commission must insist upon properly vetting the significantly increased cost projections" and reiterates its recommendation to do so in follow-on CPCN proceedings.[167] Staff argues that Public Service provides little more than the "limited and cursory explanations for the increases in the right-hand column of Hearing

[164] Hr. Ex. 166 (Ihle), pp. 57-58.
[165] Hr. Ex. 2709 (Staff Response), p. 39.
[166] Hr. Ex. 2709 (Staff Response), p. 40.
[167] Staff's SOP, p. 9.

Exhibit 2718HC."[168] Staff further asserts that neither the Commission nor any of the intervenors have had an adequate opportunity to vet the reasons the Company gives for the surges in projected costs. [169]

128. In its Response Testimony, CEO similarly argues that Public Service has not provided detailed information demonstrating which costs have increased, by how much, and why. Without this information, CEO argues, the Commission cannot reasonably determine if the new baseline costs the Company proposes are reasonable. CEO asserts that more detailed cost comparisons and explanations should be provided in future CPCN proceedings, where any prudency requests can be addressed.[170]

129. Interwest recommends that the Commission require Public Service to treat all projects equally in the CEP Delivery Plan to ensure fairness, transparency, and system reliability. According to Interwest, utility-owned projects should be treated in the exact same manner as IPP owned generation, and thermal generation should be treated in the exact same manner as renewable generation. [171]

130. CEC and UCA argue the Commission should retain the project-specific CtC PIMs with no adjustment to the baseline. CEC asserts that modifying the CtC PIM at this juncture would fundamentally disrupt the purpose of the CtC PIM and set a precedent that utilities can simply dodge PIM disincentives if project costs increase. According to CEC, customers should be protected from the cost increases that the IE Report predicted.[172] UCA similarly argues the CtC

[168] Staff's SOP, p. 8.
[169] Staff's SOP, pp. 8-9.
[170] Hr. Ex. 1204 (CEO Response Testimony), pp. 20-21.
[171] Interwest's Comments, pp. 6-7.
[172] CEC's Comments on CEP Delivery, pp. 8-9.

PIM is intended to protect customers against price increases and thus it would be unreasonable to adjust the baseline for a CtC incentive for a price increase.[173]

131. In its Reply Comments, the Company continues to argue that application of Rule 3617(d) and its presumption of prudency to the updated costs for Bid 0989, Bid 1000, and Bid 0011 is appropriate. The Company reasons that it has presented updated pricing with more detail and background than is typically provided in a Phase II process, and this is an ERP where Rule 3617(d) applies to projects receiving approval. Public Service states that a presumption of prudence would provide the Company regulatory certainty to move forward with CPCN filings for these units where the costs can be examined in more detail and a final determination regarding the costs for the project, including the CtC baseline, can be established by the Commission.[174]

132. Nevertheless, the Company acknowledges that several intervenors raise concerns with this concept.[175] If the Commission declines to apply Rule 3617(d), the Company proposes an alternative pathway that it states is responsive to the proposals from Staff and CEO to use the CPCN proceedings reestablish the individual CtC baselines. The Company alternative proposal is for the Commission to make the following findings:

> Finding 1: Prudently incurred costs associated with each of the projects will be eligible for recovery.
>
> Finding 2: Costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and Operational PIM baselines, as determined in the CPCN proceeding.
>
> Finding 3: For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing are—if established by the utility to have cost impacts on the project as delivered compared to the CtC baseline—extraordinary circumstances within the terms of the CtC

[173] Hr. Ex. 509 (UCA Testimony), pp. 27-28.
[174] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 18-19.
[175] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18.

> PIM, subject to future adjudication by the Commission following development of the project in question. Similarly, although potentially less applicable, the same would be true for the Operational PIM.[176]

133. Public Service states that, in the absence of a Rule 3617(d) application to the updated cost estimates, making the above three findings offers an alternative path forward.[177]

134. In its SOP, Public Service does not discuss the alternative approach of making certain findings prior to CPCNs. Instead, Public Service argues the Commission should move forward with the Company's primary recommendation to approve CtC baseline adjustments consistent with the Company's presentation in the CEP Delivery Motion. The Company asserts that intervenors "have conducted extensive discovery relating to these projects over the last two months, and will have an opportunity for additional review in future proceedings as the projects are brought online."[178]

### 2. Findings and Conclusions

135. We agree with Staff and CEO that the requested cost increases for the thermal resources should be examined in follow-on CPCN proceedings before deciding whether the incremental costs are entitled to a presumption of prudence or warrant adjustments to the CtC PIM baseline. The Commission finds unpersuasive the Company's arguments that it has presented updated pricing with more detail and background than is typically provided in a Phase II process and thus is entitled to Rule 3617(d)'s presumption of prudence. In a typical Phase II process, there is competitive tension and various resource options. These elements are largely lacking in the context of the CEP Delivery Motion's requested price increases for thermal units. Moreover, it is

[176] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 19.
[177] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 20.
[178] Public Service's SOP, p. 9.

far from clear that Public Service has presented detailed information regarding the requested price increases; Staff's assertions support the opposite conclusion.[179]

136. On the other hand, we disagree with CEC and UCA's suggestions to decide in this Proceeding that no adjustments to the CtC baselines are warranted. Public Service appears to raise legitimate claims that thermal generating equipment has seen significant increases in demand and cost. If established in follow-on CPCN proceedings, such cost increases may warrant adjusting the CtC PIM baseline. Similarly, we decline from adopting at this juncture Interwest's position that thermal resources should be treated the same as renewables.

137. In connection with our decision to evaluate the proposed cost increases in the follow-on CPCN proceedings, we largely agree with Public Service's alternative proposal to make certain findings regarding how such cost increases will be evaluated going forward. The thermal projects that have earned a presumption of prudence in this Proceeding will advance to the CPCNs with this presumption of prudence intact as to the project's as-bid amounts. In the CPCN proceedings, the Commission could determine the incremental costs above the project's as-bid amounts potentially constitute extraordinary circumstances and accordingly adjust both the CtC baseline and the level of costs that carry a presumption of prudence.

138. For clarity, we adopt the Company's three requested findings, with the below modifications. As determined in the respective CPCN proceedings, costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and operational PIM baselines. For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing may potentially constitute extraordinary circumstances within the terms of the CtC PIM (*i.e.*, unforeseen costs that could not have been known at the time the bid was

[179] Staff's SOP, p. 8.

made), subject to future adjudication by the Commission following development of the relevant project. Similarly, although potentially less applicable, the same would be true for the operational PIM. Moreover, prudently incurred costs associated with each of the projects will be eligible for recovery; provided, however, that this in no way impacts the application of the PIMs. For instance, the Company may earn a disincentive under the CtC PIM regardless of whether the underlying costs are imprudent.

## K. Bid 0989

### 1. Party Positions

139. As part of the CEP Delivery Motion, Public Service requests Commission approval to remove the SCR system from Bid 0989.[180] The Company argues the SCR system is not required for environmental permitting and that its removal will result in cost savings and operational advantages.[181]The Company explains that it initially assumed the unit would need an SCR to meet environmental permitting requirements. After further examination, based on permitting requirements, projected capacity factor and operating characteristics, Public Service now maintains that the SCR is not necessary and the unit can be permitted and operated without it. Public Service acknowledges that removing the SCR will likely lower the unit's permitted capacity factor, but the Company states that the lowered capacity factor is still above the range it expects to need for this unit.[182]

140. Public Service states it needs certainty from the Commission on this point in order to commence the air permitting process with the Colorado Department of Public Health and the Environment ("CDPHE"). Public Service asserts that if the Commission defers deciding whether

[180] CEP Delivery Motion, p. 9.
[181] Hr. Ex. 166 (Ihle), p. 75.
[182] Hr. Ex. 166 (Ihle), pp. 75-76.

to remove the SCR, the Company would need to proceed with the SCR for permitting reasons, which would result in "unnecessary costs to customers."[183]

141. In its SOP, Public Service clarifies that the Company is not asking the Commission to either approve anything regarding the permitting of Bid 0989 or approve operational characteristics for Bid 0989. Instead, "the Company simply requests the Commission acknowledge that moving forward without the SCR is permissible in light of the fact that this is a difference from the as-bid configuration."[184]

142. Staff argues the Commission should proceed with caution regarding the removal of the SCR device. Staff notes that the Company's Phase II modeling and bid assumed that an SCR would be installed for this unit. Staff is particularly concerned about the Company's representations regarding the capacity factor at which the unit can operate without the SCR. Staff argues the Commission should find a way forward in which it can quickly vet the Company's cost-reduction claims as well as to verify potential operational concerns associated with removing the SCR. To do this, Staff suggests the Commission direct parties to address the removal of the SCR as part of an operational PIM proceeding.[185]

### 2. Findings and Conclusions

143. We share Staff's concern that removing the SCR from Bid 0989 might change how Public Service can operate the unit as compared to the Phase II modeling. Public Service has testified, however, that the lowered capacity factor the unit would have without the SCR is not expected to change Public Service's use of the plant and that there is insufficient time to fully

[183] Hr. Ex. 166 (Ihle), p. 76.
[184] Public Service's SOP, p. 10.
[185] Staff's SOP, p. 11; Hr. Ex. 2709 (Staff Response), p. 44.

evaluate the operational changes before Public Service must initiate the permitting process with CDPHE.

144. Based on the Company's representations in testimony, the Commission grants the Company's clarified request in its SOP and acknowledges that moving forward without the SCR is permissible even though doing so is different than the as-bid configuration. Public Service has put forth evidence that removing the SCR will save ratepayers considerable money without interfering in the planned operation of the unit nor the value it is expected to provide ratepayers. CDPHE is tasked with determining the exact impacts that removing the SCR will have on the plant's operations.

145. Nevertheless, if Public Service moves forward with Bid 0989, the issues surrounding the SCR device will need to be more closely examined in the follow-on CPCN proceeding. Public Service's position that the SCR device is unnecessary is based on assumptions regarding how the Company will use the unit. However, there are several uncertainties that might impact the planned use of the unit, including developments with beneficial electrification, large new loads, and the potential entry into a regional market. If such changes alter the calculus for whether the additional operational flexibility granted by use of the SCR device is beneficial, the Commission will scrutinize whether any incremental costs should fall on Public Service's ratepayers.

146. Similarly, we intend to examine in any future CPCN for Bid 0989 whether there should be a mechanism (*e.g.*, a PIM) to ensure the accuracy of the Company's representations regarding the capacity factor of the unit and the role the unit has in the system. One of the primary purposes of thermal units such as Bid 0989 is to help ensure Public Service has the capacity it needs when the system is peaking. If the Company's removal of the SCR device were to impact

the unit's ability to serve its purpose, we would have significant concerns as to whether ratepayers are receiving the intended benefits of the unit and may find the need to guard against this eventuality at the onset of the project.

## L. Bid 0011

### 1. Party Positions

147. Bid 0011 is a 50 MW thermal resource in Alamosa County. The project is being developed and built by Mainspring, but as bid, Public Service would purchase, own, and operate the unit. As with the other thermal units in the approved Alternative Portfolio, Public Service now seeks price flexibility regarding Bid 0011.[186] However, unlike the other thermal units, Bid 0011 claims designation as a "Section 123 resource" as explained in the Phase II Decision.

148. UCA recommends the Commission reject Bid 0011. UCA asserts the life of the Mainspring generators is unknown given that the Mainspring's first commercial units were deployed in 2020. UCA also points to hearing questions that show Mainspring only has about 20 MW of projects in the field.[187] UCA goes on to assert that the price of Bid 0011 is excessive and not competitive with other projects, especially if Bid 0011 fails to qualify for ITC tax benefits. As an alternative, UCA recommends the Commission approve extending the life of the existing Alamosa CTs as a bridge to the JTS.[188] UCA also suggests that some of the Plains End units could be moved to the San Luis Valley to replace the capacity from Bid 011 at a much lower cost.[189]

149. Mainspring submitted testimony that Bid 0011 would reduce CO2 emissions compared to the existing plants in Alamosa County by approximately 59 percent and NOx

[186] Hr. Ex. 166 (Ihle), pp. 27-28; CEP Delivery Motion, p. 9.
[187] UCA's SOP, pp. 6-7.
[188] UCA's SOP, pp. 7-8.
[189] Hr. Ex. 509 (UCA Testimony), pp. 20-21.

emissions by approximately 99 percent on a per MWh basis.[190] Mainspring further asserts that its linear generator technology has the ability to switch between various gaseous fuels, including, but not limited to, natural gas, hydrogen, propane, and biogas. The linear generator uses a low-temperature reaction without a spark or flame, which results in near-zero emissions of nitrogen oxides. [191] With its project's fuel flexibility and ability to seamlessly change fuels without hardware or software updates, Mainspring argues the project does not have stranded asset risk of traditional thermal units. [192]

150. Mainspring notes that when it developed its bid, it did not expect that Public Service would require a third-party engineering study, and the associated cost and schedule impacts were not reflected in the bid. Mainspring argues there are similar requirements related to Bid 0011's status as a Section 123 resource that have forced Mainspring to reasonably deviate from its bid assumptions and associated pricing.[193]

151. In its SOP, Mainspring reiterates the positive attributes of Bid 0011 and notes that due to the plant's new, clean technology, it is a Section 123 resource, to which the Commission must give the "fullest possible consideration to the cost-effective implementation" of the project.[194] Mainspring additionally argues that Bid 0011 will not unreasonably shift risk to ratepayers. Mainspring asserts it has the necessary experience deploying its linear generators, noting the other projects its development team has done and the fact that the Department of Energy recently awarded Mainspring an $87 million grant to build a manufacturing facility to produce its linear generators.[195] Mainspring also states the Commission and parties will be able to evaluate

[190] Hr. Ex. 3001 (Igo Testimony), p. 5.
[191] Hr. Ex. 3000 (Hennessy Testimony), pp. 4-5.
[192] Hr. Ex. 3000 (Hennessy Testimony), p. 8.
[193] Hr. Ex. 3001 (Igo Testimony), pp. 8-9.
[194] Mainspring's SOP, p. 7.
[195] Mainspring's SOP, p. 10.

the build-transfer agreement with Public Service in the CPCN proceeding. According to Mainspring, a core component of the negotiations with Public Service has been reducing risk for ratepayers. Mainspring further notes that it has made substantial investments in the project that will not be recoverable if the Commission ultimately does not approve Public Service's acquisition of Bid-0011.[196]

152. In addition, Mainspring argues that advancing Bid 0011 is the best available option to meet the needs of the San Luis Valley. If the Commission removes Bid 0011 in place of other options that were not competitively bid, Mainspring argues it would undermine the entire Phase II process and potentially chill future competitive solicitations in Colorado. Such a result would also arguably violate Commission Rule 3605(h)(II)(A), which provides that in an ERP proceeding, a Phase II decision "shall establish the *final* cost-effective resource plan."[197] Mainspring specifically critiques UCA's recommendation to move some of the Plains End units to the San Luis Valley as a replacement for Bid 0011. Mainspring asserts there is no analysis on the feasibility of this option and, because Plains End will emit more emissions than the linear generator, such a move would be contrary to the Commissions statutory obligation to account for and help correct the historical inequities faced by disproportionately impacted communities in Colorado.[198] Mainspring also adds the record does not support extending the life of the existing Alamosa CTs.

153. Although Staff initially recommended eliminating Bid 0011 due to its price increase, Staff changed its position after reviewing Mainspring's testimony. In its SOP, Staff now asserts the Commission "should no longer consider dropping Bid No. 0011."[199] Staff recommends the Commission vet the projected cost increases in the CPCN proceeding, arguing that determining

[196] Mainspring's SOP, p. 10.
[197] Mainspring's SOP, p. 13 (emphasis in original).
[198] Mainspring's SOP, pp. 13-14.
[199] Staff's SOP, p. 9.

whether the price increase drivers truly constitute justifiable projected cost increases is an ideal topic for a CPCN proceeding.[200]

154. In Public Service's SOP, the Company continues to recommend moving forward with Bid 0011 at the requested price increase. The Company appreciates Staff's recognition of the importance of Bid 0011. Public Service states that the alternative—life extensions of the existing units at Alamosa—is not preferable, given that they leave the same location-specific capacity hole after 2030.[201]

### 2. Findings and Conclusions

155. The Commission generally agrees with Public Service, Staff, and Mainspring. Consistent with the other approved thermal resources, Public Service may advance Bid 0011 to the CPCN proceeding, and Rule 3617(d)'s presumption of prudence will remain intact as to the project's as-bid amounts. The Commission will evaluate in the CPCN proceeding whether the incremental costs of the project also warrant a presumption of prudence and whether the CtC PIM baseline for the project should be adjusted as set forth above.

156. We reject UCA's recommendation to use the existing CTs as a bridge until new resources can be acquired in the JTS. The existing thermal resources in Alamosa are aging, and Public Service raised reliability concerns with these plants in the 120-Day Report. UCA's recommendation simply delays when a replacement thermal resource is constructed in Alamosa, with no guarantee that future thermal resources would be more cost effective. We likewise reject UCA's suggestion to move some of the Plains End units to the San Luis Valley. There is insufficient record support for this proposal.

[200] Staff's SOP, p. 10.
[201] Public Service SOP, p. 11.

157. Although Public Service may move forward with Bid 0011 consistent with the other approved thermal resources, we are concerned about the price and size of Bid 0011 and the associated risks to ratepayers. At the same time, we continue to acknowledge the potential fuel flexibility associated with this plant and the potential for benefits in that regard. Accordingly, we direct Public Service to present in the CPCN proceeding as a potential alternative an approach in which the size and costs of the project are reduced. As an example of this alternative option, the Company could consider structuring the build-transfer agreement more as a purchase option and pre-construction development asset with Mainspring. Under such an approach, the Company might have a unilateral option to purchase the project at an agreed upon matrix of prices, with flexibility to adjust the final size of the project. In return for this option, and in addition to the purchase price, the Company could compensate Mainspring for all of its verifiable reasonable third-party development costs at the time the option was signed. Public Service may be able to request accelerated cost recovery of these expenses through the electric commodity adjustment. We encourage the Company to explore and negotiate further this and other potential options regarding Mainspring, with the overarching intent of reducing costs and limiting risks to ratepayers.

### M. Purchase of Plains End

#### 1. Party Positions

158. In the CEP Delivery Motion, the Company states that its preferred approach is to extend the Plains End PPA. As a secondary approach, the Company suggests it could pursue purchasing the unit.[202]

[202] Hr. Ex. 166 (Ihle Testimony), p. 115.

159. In their Answer Testimony, Staff and UCA initially both urged the Commission to direct Public Service to purchase Plains End, arguing that purchasing the unit provides substantial cost advantages. UCA in particular characterized the cost-benefit of owning the plant as "massive."[203]

160. In its Reply Comments, however, Public Service argues that requiring the Company to immediately purchase Plains End is not a prudent path. The Company reasons that before purchasing an asset like Plains End, the Company would need to conduct extensive due diligence. Public Service states that it "could not commit to purchasing the unit prior to conducting due diligence without strong and unambiguous assurances that any unforeseen issues … would not be a basis for intervenor disallowance recommendations."[204] If the Company's preferred approach is approved, the Company proposes to report annually, beginning in the March 2025 ERP annual report, on the status of a potential acquisition of Plains End. [205]

161. After reviewing the Company's Reply Comments, UCA and Staff both change positions regarding the purchase of Plains End. In its SOP, Staff now argues against requiring Public Service to purchase Plains End. Staff instead recommends the Commission adopt the Company's preferred approach in which it extends the PPA. In connection with this recommendation, Staff argues the Commission should (1) require Public Service to carry out due diligence regarding the potential acquisition of the unit, and (2) direct the Company to seek Commission approval to purchase or decline from purchasing Plains End in an application filing that contains the Company's due diligence.[206]

[203] Hr. Ex. 2709 (Staff Response), pp. 29-30; Hr. Ex. 509 (UCA Testimony), pp. 16-17.
[204] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 22.
[205] Public Service's SOP, p. 12.
[206] Staff's SOP, p. 13.

162. UCA similarly recommends that Public Service extend the PPA and perform due diligence on the condition of the plant and the costs for the Company to operate it. Depending on the results of the due diligence, UCA recommends the Company purchase Plains End as soon as possible.[207]

### 2. Findings and Conclusions

163. We approve the Company's preferred approach of extending the Plains End PPA and then conducting due diligence into a potential acquisition of the unit. To be clear, as argued here, we find that the Company has met its burden and extending the Plains End PPA is entitled to a presumption of prudence.

164. Consistent with the Company's position, Public Service shall report annually, beginning in the March 2025 ERP annual report, on the status of a potential acquisition of Plains End. We also adopt Staff's additional proposal and require Public Service to carry out the due diligence and direct the Company to seek Commission approval to purchase or decline from purchasing Plains End in an application filing that contains the Company's due diligence.

165. While we ultimately agree with Public Service's preferred approach regarding Plains End, the Company's decision to wait until September 2024 to seek regulatory approval regarding Plains End is incredibly frustrating. If the Company would have brought Plains End to the Commission earlier, there might have been additional options for cost savings for ratepayers. There is insufficient information to address that concern raised by parties here. While the Company's preferred approach appears to be the only prudent presented option moving forward based on this record and at this very late stage, our determination only addresses prudency of extension given the record before us. In a subsequent proceeding stakeholders may argue whether

[207] UCA's SOP, p. 2.

Public Service fails to demonstrate the prudency of its decisions to delay seeking regulatory approval regarding Plains End.

### N. Alternative Thermal Proposals

#### 1. Party Positions

166. In its Response Testimony, UCA puts forth an alternative thermal proposal that includes Bid 1000 but then adds a another two CTs at an existing gas-fired generator station. UCA argues that adding CTs at this existing site provides important transmission support as an existing gas-fired generator, Cherokee 4, retires. UCA asserts that its thermal proposal provides 1,019 MW of economical thermal capacity.[208]

167. UCA continues to advance its alternative thermal proposal in its SOP, reiterating the importance of adding additional generation at Cherokee. Relatedly, UCA asks that the Commission direct Public Service to delay the Cherokee 4 retirement date by a year. UCA argues that delaying the retirement will improve the reliability of the Company's system and help address the projected capacity shortfall in 2028.[209]

168. CEC offers a similar, but broader, recommendation that the Commission consider extending existing thermal generation capacity as necessary to meet load growth and maintain reliability in the face of lost capacity from withdrawing clean energy projects. CEC asserts that Xcel Energy affiliate Southwestern Public Service Company has turned to extending thermal generating units as it transitions its generation fleet to meet New Mexico's emissions reduction goals. CEC argues the Commission should require Public Service to explore similar opportunities here.[210]

[208] Hr. Ex. 509 (UCA Testimony), pp. 20-21.
[209] UCA's SOP, p. 3.
[210] CEC's Comments on CEP Delivery, p. 8.

169. Another alternative proposal from UCA is that the San Luis Valley should have enough capacity to allow it to be "islanded" if the two transmission lines connecting the San Luis Valley are lost. UCA asks the Commission to direct Public Service to provide summer and winter load and gas-pipeline capacity data for the San Luis Valley, with the load data also showing how much load could be curtailed in case the transmission lines are lost. UCA recommends Public Service provide a plan for how much capacity, including gas, storage, and demand management, is needed to island the San Luis Valley if the transmission lines are lost.[211]

### 2. Findings and Conclusions

170. The Commission denies UCA's alternative thermal proposal and recommendation to require Public Service to delay the retirement of Cherokee 4. There is insufficient record support for UCA's proposals. We likewise decline CEC's recommendation to require Public Service to explore extending the lives of existing thermal units. Public Service is responsible for reliability and should already be evaluating all potential options to ensure resource adequacy.

171. We also do not support UCA's recommendation to require Public Service in this Proceeding to submit an analysis of the amount of additional capacity that would be necessary to island the San Luis Valley. UCA can always advocate for such an analysis in the JTS if it wishes to do so.

## O. Expansion of ISOC Incentives

### 1. Party Positions

172. Public Service seeks authorization to increase the incentives under the ISOC program to encourage more DR capacity. Public Service argues that expansion of this program is most likely to produce incremental growth in short term DR. The ISOC program uses direct-load

[211] UCA's SOP, pp. 8-9

control and provides a minimum of ten minutes notice to customers prior to controlling the customer's load. Legacy or "grandfathered" customers receive a foundational bill credit of $15.97/kW-mo, but new customers currently receive a bill credit of only $11.27/kW-mo. At this lower incentive, however, Public Service states that only one customer has enrolled in the program since 2019.[212] The Company asks that the Commission increase the "new" program incentive to match the "legacy" incentive of $15.97/kW-mo through 2028.

173. CEO supports increasing the ISOC incentive back to its legacy level on a pilot basis with additional reporting. CEO reasons this will allow the Company to gather information about the willingness of customers to enroll in the ISOC program at the adjusted incentive level. CEO recommend the Commission direct Public Service to provide any learnings and data collected from the pilot both in its 2026 Demand Side Management ("DSM") Strategic Issues proceeding to assess the potential capacity impacts of the ISOC incentive and in its annual DSM Status Report.[213]

174. In its Response Testimony, UCA recommends the Commission reject the Company's proposal to expand the ISOC program, arguing Public Service has not provided enough information to enable the Commission to perform an adequate evaluation of its proposal. UCA specifically asserts Public Service has not provided the additional capacity that could be expected nor provided the additional cost of increasing program incentives.[214]

175. Staff likewise recommends rejecting Public Service's ISOC proposal. Staff argues the ISOC proposal does not belong in this Proceeding. Staff further asserts that since modifying the ISOC program requires changing the Company's interruptible service tariff, an advice letter filing is the proper vehicle for Public Service to seek approval of its ISOC proposal.[215]

[212] Hr. Ex. 166 (Ihle), pp. 118-19.
[213] Hr. Ex. 1204 (CEO Response Testimony), p. 30.
[214] Hr. Ex. 509 (UCA Testimony), p. 24.
[215] Staff's SOP, p. 14 (citing Hr. Tr. November 7, 2024, p. 261).

176. Public Service continues to advocate for its ISOC proposal in its SOP, reiterating that the ISOC proposal would increase incentives for "new" load from participants to match the "legacy" incentive rate of $15.97/kW-mo through 2028. Public Service anticipates that approximately 10 additional MW of ISOC capacity could become available if the legacy pricing is expanded.[216]

177. The Company argues that Staff's suggestion to evaluate the ISOC proposal through a separate advice letter filing could take an additional eight months and would not be an efficient use of the Commission's, the Company's, or intervenors' resources. Public Service argues the proposed change is incremental, the legacy pricing rate has already been vetted and approved, and the change would only be in effect through 2028 when all ISOC pricing can be reevaluated. Public Service also notes it has committed to reporting on the results of its proposal in the ISOC annual reports. Instead of a new advice letter proceeding, Public Service argues the Commission should approve the proposal here and implement it through a compliance advice letter filing.[217]

**2. Findings and Conclusions**

178. Although the potential for additional DR capacity is attractive and aligned with the Commission's broader intent, we ultimately deny Public Service's ISOC proposal. In this relatively abbreviated process associated with the CEP Delivery Motion, Public Service has not adequately supported its proposal. For instance, there has been insufficient evidence regarding the projected costs and benefits of the Company's proposed modifications to the ISOC program. For these reasons, Public Service will need to present a more fleshed out version of its proposal in a standalone advice letter proceeding.

[216] Public Service's SOP, pp. 15-16.
[217] Public Service's SOP, p. 16.

179. Public Service complains that requiring a separate advice letter proceeding could take an additional eight months. Based on the record in this Proceeding, however, the Company has not established that an eight-month delay in acquiring perhaps an additional 10 MW of capacity warrants deviating from the Commission's standard regulatory process. We direct Public Service to file its ISOC proposal as a separate advice letter as soon as reasonably practicable.

## II. ORDER

### A. The Commission Orders That:

1. The Motion to Approve Clean Energy Plan ("CEP") Delivery Plan and for Variances from Certain Commission Rules and Decisions filed by Public Service Company of Colorado ("Public Service") on September 6, 2024, is granted, in part, and denied, in part, consistent with the discussion above.

2. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

3. This Decision is effective immediately upon its Issued Date.

**B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING December 16, 2024, and December 20, 2024.**

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-26-21 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-166
Tri-State January 2026 Press Release

# Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order



01/23/26

(January 23, 2026 – Westminster, Colorado) To comply with an emergency order from the U.S. Department of Energy (DOE) under Section 202(c) of the Federal Power Act, Tri-State Generation and Transmission Association and the other co-owners of the Craig Generating Station took the necessary steps this week to make Unit 1 available to operate.

On Dec. 30, 2025, owners of the Craig Station received the emergency order from the DOE identifying an energy emergency in the Western Electricity Coordinating Council Northwest area and directing Tri-State to keep Unit 1 available to operate at the direction of either the Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, for the next 90 days.

Unit 1 went into an outage on Dec. 19, 2025, due to a mechanical failure of a valve. Tri-State and the other co-owners took the necessary steps to repair the valve in a timely manner and as noted, the unit was available to operate by Tuesday, Jan. 20, 2026.

Retaining Unit 1 in compliance with the order will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs. Tri-State continues to evaluate how best to comply while limiting the costs to its members, and the impacts to its employees and operations. Tri-State is not providing estimates at this time for the costs that may ultimately be necessary for compliance, including recent repairs, as it is working to prepare filings in support of cost recovery.

Craig Units 1 and 2 are part of the Yampa Project, jointly owned with multiple utility services providers including Tri-State, Platte River Power Authority, PacifiCorp, Xcel Energy and Salt River Project, with Tri-State as the operating entity. Tri-State owns 100% of Unit 3. Craig Unit 1's capacity is 427 megawatts. Unit 2, with a capacity of 410 megawatts, and Unit 3, with a capacity of 448 megawatts, are scheduled to retire in 2028.

Since 2016, Unit 1 has been scheduled for retirement by Dec. 31, 2025, for economic reasons, and to comply with numerous state and federal requirements. This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's retirement.

## About Tri-State

Tri-State is a power supply cooperative, operating on a not-for-profit basis, serving electric distribution cooperatives and public power district member-owners in four states. Together with our members, we deliver reliable, affordable and responsible power to more than a million electricity consumers across nearly 200,000 square miles of the rural West. Visit www.tristate.coop.

## Contact

Amy Robertson, 303-254-3743, amy.robertson@tristategt.org

Mark Stutz, 303-254-3183, mark.stutz@tristategt.org

Certain information contained in this press statement are forward-looking statements including statements concerning Tri-State's plans, future events, and other information that is not historical information. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including those described from time to time in Tri-State's filings with the Securities and Exchange Commission. Tri-State's expectations and beliefs are expressed in good faith, and Tri-State believes there is a reasonable basis for them. However, Tri-State cannot assure you that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties and other important factors that could cause actual results to differ materially from the forward-looking statements contained herein.

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