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	)

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

Exhibit 2-131:
FERC Western Energy Markets Explainer

Western Energy Markets Explainer

This explainer offers a comprehensive overview of the electricity markets in the Western United States. It covers key features of the markets that enable coordinated and efficient management of the region's electric transmission grid system. This explainer will help you understand how new developments in electricity markets in the West may impact energy costs, system reliability, and the implementation and achievement of state-level energy policies.

This explainer is organized with four major sections:

- Key Terms
- Introduction to the U.S. Power Grid and FERC-led Initiatives to Create Wholesale Markets
- Overview of Electricity Markets in the West
- Resources to Learn More about Western Market Matters at FERC

This explainer offers a summary of publicly available information about Western markets and should not be relied upon as a legal document.

Key Terms

Balancing Authorities oversee electricity transfers and ensure grid stability by maintaining a balance between the production and consumption of electricity. They typically oversee long-term efforts to maintain that key balance on the grid, such as resource planning, as well as short-term balancing by committing electricity supply resources to operate and real-time load-frequency control within a balancing authority area. Certain electric utilities and power marketing administrations (see below) are typical examples of balancing authorities.

A **Balancing Authority Area** is a geographic region that incorporates a collection of generation facilities, transmission lines, and loads (aggregated consumer demand for electricity) where electric metering is performed by a balancing authority. The responsibility of maintaining a balance between the load and resources (supply of electricity) within this area falls under the jurisdiction of the balancing authority. One example of a balancing authority area is a utility service territory.

Congestion occurs when a portion of the transmission grid becomes overloaded with electricity. Congestion can occur when a line or transformer reaches its limit and cannot carry

any more electricity. When congestion occurs, the lowest-priced electricity cannot flow freely to a specific area.

Congestion Revenue Rights are financial tools used to manage the cost variability of congestion on the grid based on the electricity pricing approach used, called locational marginal pricing (see below). Such rights are often acquired to hedge against congestion costs in the day-ahead market, but sometimes are purchased as an investment.

A **Day-Ahead Market** is a voluntary financial market where individuals and companies can buy and sell wholesale electric energy at financially binding prices for the next day.

Hedging is the act of engaging in transactions to reduce risk from price volatility (see below) for a company and/or customers. Hedging transactions can help electricity suppliers meet their customers' demands while reducing or eliminating the risk of fluctuating prices.

Locational Marginal Pricing or Prices (LMP) refer, respectively, to the overall pricing scheme or the actual prices paid for wholesale electric energy at a specific location within an electric transmission grid at a specific point in time. LMP data is used to track the prices of electricity in different parts of the grid and to help manage supply and demand for electricity.

Price Volatility describes how quickly or widely prices can change. In the energy industry, price volatility can refer to electricity or natural gas supply prices, relative to consumer demand. Volatility is measured by the day-to-day variation (percentage difference) in the price of the commodity.

A **Power Marketing Administration** is a federal agency within the Department of Energy that markets electric power produced by federal dams and multiple-purpose water projects providing service to customers.

A **Real-Time Energy Market** is a spot market that allows consumers, companies, and energy distribution businesses to buy and sell wholesale electric energy in real-time, usually an hour before delivery. The real-time market balances the differences between day-ahead resource commitments and demand forecasts and the actual real-time demand for and production of electricity.

Resource Adequacy is the ability of an electric transmission grid to meet consumer demand for power. Resource adequacy ensures that there is enough energy generating capacity and reserves to maintain a balanced supply and demand across an electric system.

Wholesale Electric Energy, also referred to as wholesale electricity, is electric energy that is purchased or sold for resale, whereas retail electric energy is electric energy that is purchased by or sold to the ultimate consumer.

California ISO Extended Day-Ahead Market is a voluntary day-ahead electricity market designed to deliver significant reliability, economic, and environmental benefits to balancing areas and utilities throughout the West. The initial structure of EDAM was approved, in most part by the Commission in December 2023.

Introduction

In the U.S., the power grid is a complex network of power plants and transmission lines with extra-high-voltage connections between utilities. This expansive infrastructure allows the movement of electricity from one part of the network to another.[1] Over time, the U.S. power grid has evolved into three large interconnected systems, which are shown in Figure 1:

1. the Eastern Interconnection that operates in states east of the Rocky Mountains
2. the Western Interconnection that covers the Pacific Coast to the Rocky Mountain states
3. the Texas Interconnected System, known as ERCOT

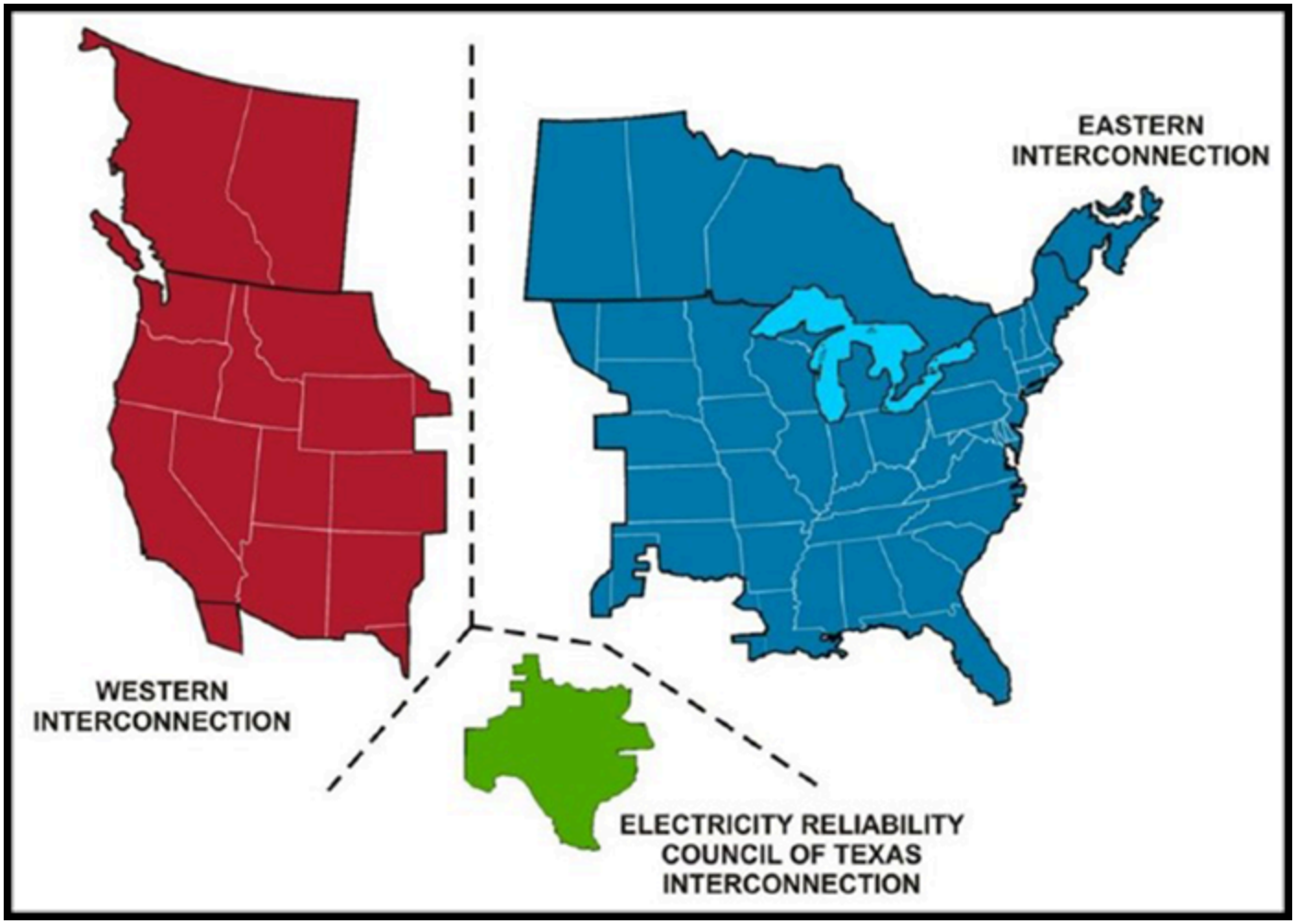


Figure 1. The Three Major Interconnections of the U.S. Electric Power Grid. Source: North American Electric Reliability Corporation.

The electric grid must comply with standards developed by the North American Electric Reliability Corporation (NERC) to ensure reliability of the grid. Because these three systems encompass unique geographic areas, NERC also assigns responsibilities to six regional entities who apply standards and act as compliance authorities. In the Western Interconnection, the Western Electricity Coordinating Council (WECC) is the regional entity, which oversees bulk power system reliability and security in the region. [2]

In the late 1990s, FERC initiated significant reforms in the electricity sector to support competition in the energy marketplace. The milestones included:

- Order No. 888 (1996): established the foundation for organized wholesale markets by promoting independent system operators (ISOs).[3] These entities were designed to foster competition among electricity generators at the wholesale level.
- Order No. 2000 (1999): encouraged utilities to join regional transmission organizations (RTOs). The aim was to enhance the operation of transmission systems and to develop equitable transmission management practices.[4]

Today, RTOs and ISOs play a crucial role in electricity policy. They serve approximately two-thirds of U.S. electricity consumers, managing both power markets and regional transmission systems (Figure 2 shows the boundary areas the RTO and ISO regions).[5]

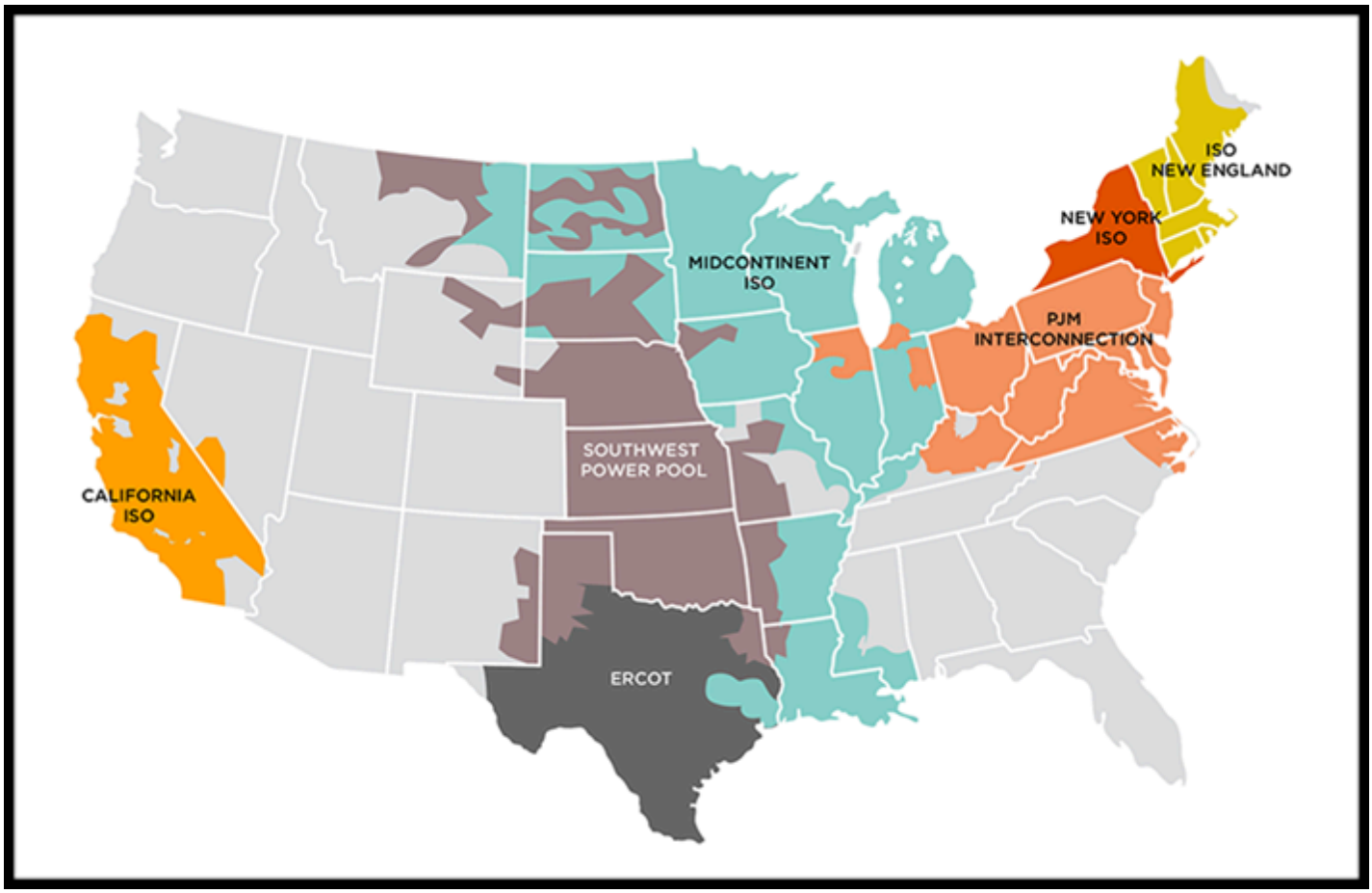


Figure 2. Seven RTO and ISO Regions in the Continental United States.

The West has progressively developed its regional wholesale electricity markets, adopting new systems and improvements step-by-step. Unlike other regions that may implement large-scale changes all at once, the West has chosen to evolve its electricity markets gradually, with each stage of development building upon the last.[6] For example, a single organized market manages energy trades for most of California—the California Independent System Operator (CAISO)—and there are currently no multistate RTOs (although, as seen in Figure 2, CAISO territory includes a small area of Nevada).[7]

The West uses a coordinated system of regional real-time energy supply markets and bilateral trading between a specified buyer and a specified seller of electricity. The Western Area Power Administration and the Bonneville Power Administration, two Western Power Marketing Administrations within the Department of Energy, sell electric power produced by federal dams to utilities (Figure 3 shows the boundary areas of the four Power Marketing Administrations).

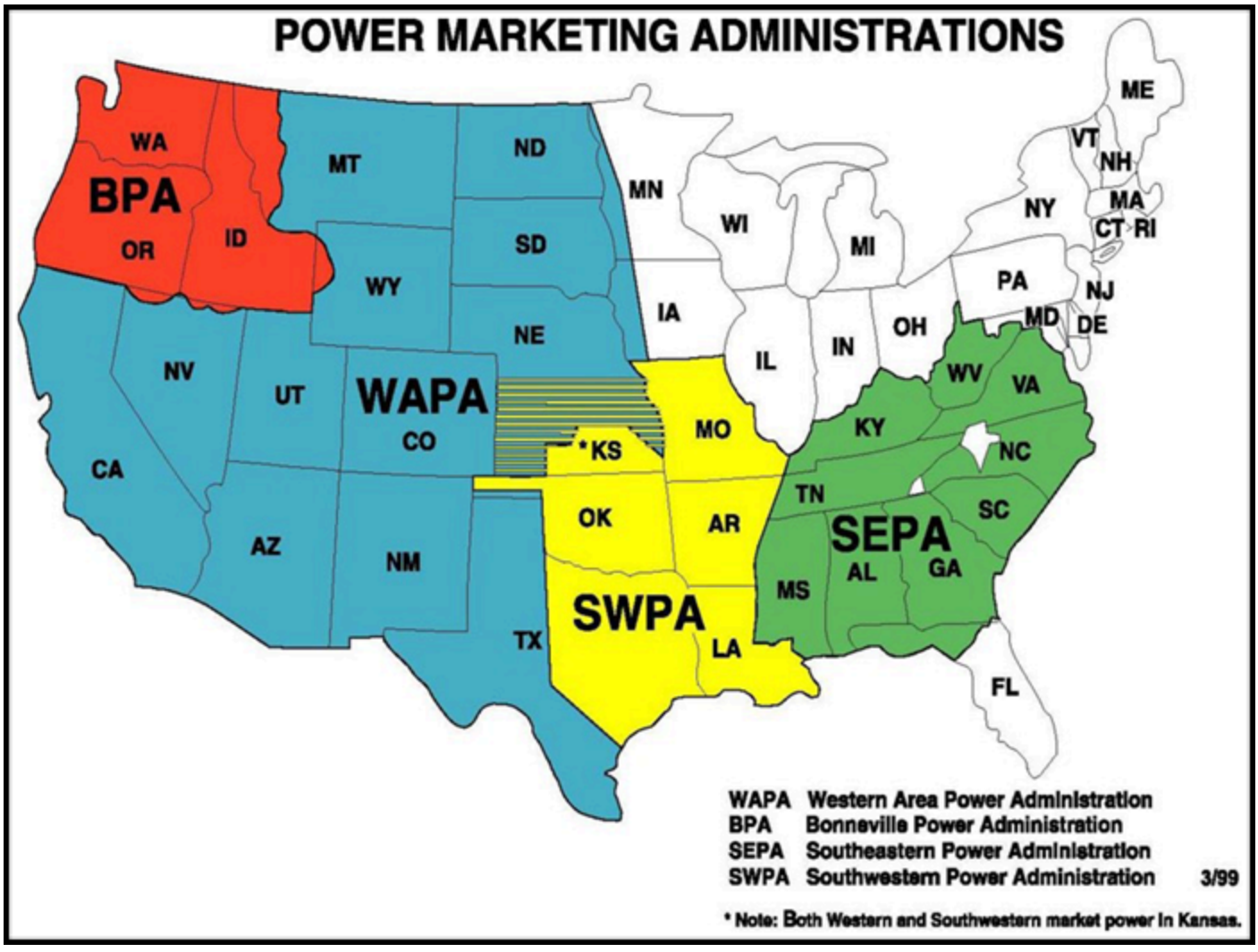


Figure 3. Power Marketing Administrations in the Continental United States. Source: SPP

While CAISO is currently the only ISO in the West, FERC has approved several market initiatives in the last twenty years that have led to a more integrated Western electric system that

encompasses several Western states. The rest of this explainer will discuss CAISO as well as other initiatives and entities that contribute to the region's electricity landscape.

Overview of Electricity Markets in the West

California Independent System Operator (CAISO)



Figure 4. California Independent System Operator (CAISO) area.

The California Independent System Operator (CAISO)[8] was founded in 1998 and became a fully functioning ISO in 2008. CAISO manages the flow of electricity across the high-voltage, long-distance power lines serving 80% of California and a part of Nevada (Figure 4 shows the boundary areas of CAISO).[9]

CAISO provides open access to the transmission lines it operates and performs long-term transmission planning. In managing the grid, CAISO centrally dispatches generation and coordinates the movement of wholesale electricity in the area shown. CAISO's wholesale energy markets comprise day-ahead and real-time processes that include energy products, such as real-time energy, day-ahead energy, ancillary services, and congestion revenue rights. The Commission also approved, in most part, CAISO's Extended Day-Ahead Market proposal in December 2023.

Western Energy Imbalance Market (WEIM)

In 2014, CAISO initiated the Western Energy Imbalance Market (WEIM) with the purpose of expanding real-time market access to utilities in the Western Interconnection who are not members of CAISO. Utilities participating in the WEIM include utilities and balancing authorities outside of CAISO's territory. Among other benefits, the WEIM provides its participants with access to least-cost electricity across the region. There are also operational and reliability benefits to the sharing of electricity through WEIM. For example, when one part of the West is experiencing an electric energy shortage while others are not, there can be sales of excess electric energy to the area that needs it.

Concerning day-to-day operations, the WEIM is a real-time energy market that allows participating utilities to balance their supply and demand within 15 minutes or 5 minutes of delivery using the least-cost resources available across a wider footprint, helping to manage system needs. This creates a coordinated system of regional real-time energy supply markets, which, while not a full RTO or ISO, offers a structured approach to energy trading and system balancing in the West.

Since the WEIM began offering real-time market access to utilities outside of CAISO's territory, the WEIM has grown to serve parts of Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Texas, Utah, Washington, and Wyoming, and extends to the border with Canada and Mexico, totaling 22 participating entities representing 79% of the energy load in the WECC.[10] The WEIM's ability to leverage CAISO's market optimization tools to service the needs of the utilities outside its ISO structure have led to reported cost-savings.[11] Presently, the WEIM claims to have delivered more than $5 billion in benefits by connecting a broader area with access to lower-cost electricity.[12]

The WEIM is governed by a five-member body with shared authority from the CAISO Board of Governors on rules specific to participation in the WEIM.[13] As designed by regional stakeholders, the WEIM Governing Body is nominated by a committee of Western stakeholders. The WEIM Governing Body and CAISO Board of Governors frequently hold public sessions that include a toll-free number for members of the public to listen to the meeting. These public sessions include opportunities for public comment following briefings on policy initiatives as well as WEIM benefits and market updates.

Southwest Power Pool (SPP)

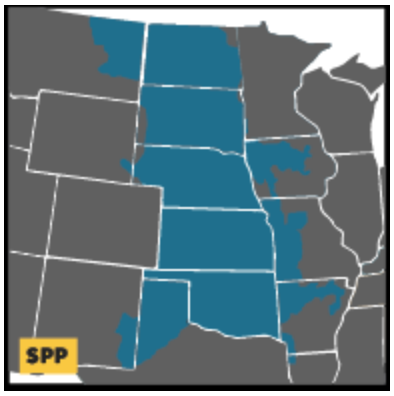


Figure 5. Southwest Power Pool (SPP) area.

The Southwest Power Pool (SPP), an RTO operating primarily in the Midwest, operates energy markets in both the Eastern and Western interconnections. Founded in 1941 as an 11-member power pool that allowed for power sharing among participating utilities, SPP achieved RTO status in 2004. Based in Little Rock, Arkansas, SPP manages transmission in portions of fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Its membership comprises investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers, and independent transmission companies.

In 2015, SPP's footprint expanded when the Western Area Power Administration—Upper Great Plains (WAPA-UGP) region, the Basin Electric Power Cooperative, and the Heartlands Consumer Power District—joined the RTO. The expansion nearly doubled SPP's service territory and added more than 5,000 MW of peak demand and over 7,000 MW of generating capacity. WAPA-UGP is the first federal power marketing administration to join an RTO.

In January 2025, FERC also approved, subject to condition, SPP's Markets+ proposal.

Additionally, in March 2025, FERC approved, subject to condition, SPP's RTO West proposal.

Western Energy Imbalance Service (WEIS) Market

In 2020, SPP established the Western Energy Imbalance Service (WEIS) market with the purpose of providing real-time market access to utilities in the Western Interconnection who are not members of the SPP RTO. Like CAISO's WEIM, SPP's WEIS seeks to provide participants with access to least-cost electric energy and to create reliability and operational advantages, such that power from areas with excess electric energy can flow to an area experiencing a shortage (such as during a weather emergency).

WEIS centrally dispatches generation to balance supply and demand in real-time and allows parties to continue to trade wholesale electricity bilaterally. Additionally, the WEIS has a goal of allowing participants to hedge against transmission congestion while coordinating the

movement of wholesale electricity. In 2022, according to the WEIS Benefit of Market Report, WEIS claims to have provided $31.7 million in net benefits to its 12 participating Western utilities.[14]

SPP's independent Board of Directors provides ultimate oversight of the WEIS's administration; however, the Western Markets Executive Committee is responsible, through its designated working groups, committees, and task forces, for developing and recommending policies, procedures, and system enhancements related to the administration of the WEIS by SPP under the Western Joint Dispatch Agreement in the Western Interconnection.[15] In coordination with the Western Markets Executive Committee, the Western Markets Working Group provides a public forum for customers to engage in matters of governance and strategy with other stakeholders.[16] In 2024, all Western Markets Executive Committee meetings will be joint with the Western Markets Working Group. Members of the public may register on www.SPP.org for these meetings and attend in-person or by phone.

Western Power Pool (WPP)



Figure 6. Western Power Pool (WPP) area. Source: WPP

The Western Power Pool (WPP), previously known as the Northwest Power Pool, is a group of utilities and other entities that coordinate and share resources in the Western Interconnection (Figure 6 shows the boundary areas of WPP). The WPP provides services to its members, such as transmission planning and tariff administration.[17] The WPP was formed in 1983 to promote increased efficiency, competition, and coordination in the electric power industry.[18] The WPP is governed by a Board of Directors, a Governing Body, and various committees and working groups that represent the interests of its members and stakeholders. The WPP also collaborates with other regional entities, such as the WECC, SPP, and CAISO, to enhance the reliability and efficiency of the Western Interconnection. While the WPP does not provide transmission service and is not an RTO/ISO, it does provide significant benefits by ensuring reliable energy capacity and reserves across the electric system.

To that end, in August 2022, the WPP filed at FERC the Western Resource Adequacy Program (WRAP) proposal, in Docket No. ER22-2762, which is intended to enhance resource adequacy. Resource adequacy ensures that there is enough energy capacity and reserves to maintain a balanced supply and demand across the electric system.[19] The WRAP was approved by FERC in February 2023 and is expected to launch in mid-2025.[20]

Western Resource Adequacy Program (WRAP)

The WRAP is not an organized market like CAISO's WEIM or SPP's WEIS but is instead a program WPP runs to ensure that the electricity supply in the West can meet the demand and reliability needs of customers. When implemented, the WRAP will have two main components: (1) a forward showing program, where participants demonstrate their ability to meet their peak demand plus a reserve margin for the next year; and (2) an operations program, where participants monitor and report their daily resource availability and demand as well as comply with dispatch instructions from the program operator. SPP acts as the program operator and, as directed by WPP, provides services for the WRAP, such as modeling, analytics, real-time operations, and technical improvement.

The WRAP is designed to be compatible with existing markets and programs in the West, such as the WEIM and the CAISO markets. The WRAP is also open to area participants who want to join the program and benefit from its regional approach. The WRAP seeks to help participants address the challenges of resource adequacy in the West in a manner consistent with state goals, such as increasing demand, retiring coal plants, and integrating variable renewable energy sources.[21]

To Learn More

Additional information on the topics discussed is available on FERC's website, including the FERC rulings cited in this explainer, the 2024 Energy Primer, as well as on the:

- CAISO website
- SPP website
- WPP website

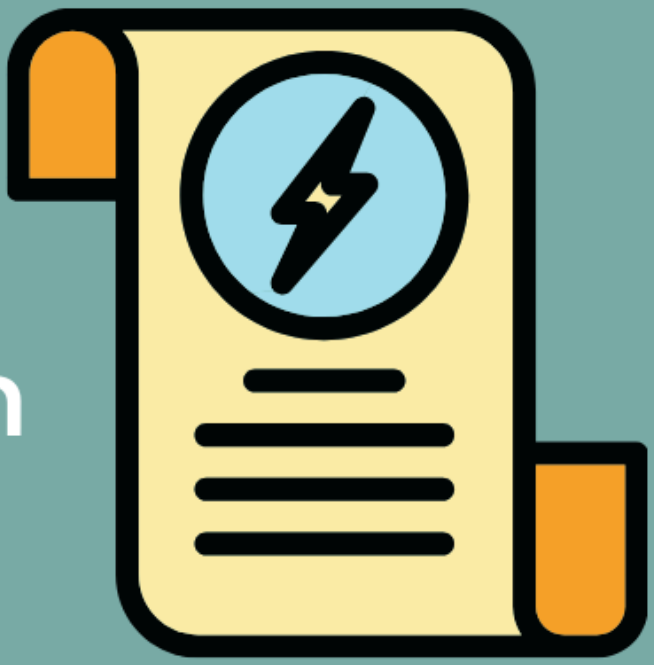
In addition to the existing markets and programs discussed above, the Western area markets may continue to develop and change. To follow FERC matters relevant to the expansion of the Western markets, you may:

- Subscribe to the Office of Public Participation (OPP) newsletter;
- Follow stakeholder processes with the stakeholder centers of CAISO and SPP; and
- eSubscribe to electronically receive information related to a particular FERC docket or set of dockets in which you have an interest.

OPP is dedicated to helping the public understand and participate in FERC proceedings. Members of the public can contact OPP for assistance in navigating FERC proceedings and receiving information on when and how to comment, intervene, or file motions during proceedings.

Please contact OPP by e-mail at OPP@ferc.gov, by phone at (202) 502-6595, or see our website at www.FERC.gov/OPP for additional information and resources.

Western Markets Expansion



CAISO

Order No. 2000

CAISO ISO Open Access Transmission Tariff (OATT)

Western Energy Imbalance Market WEIM (CAISO)

147 FERC ¶ 61,231 (2014)

Docket No. ER14-1386

EIM Section to CAISO OATT

Western Energy Imbalance Service WEIS (SPP)

173 FERC ¶ 61,267 (2020)

Docket Nos. ER21-3/ER21-4

WEIS OATT

Western RA program WRAP (Western Power Pool)

182 FERC ¶ 61,063

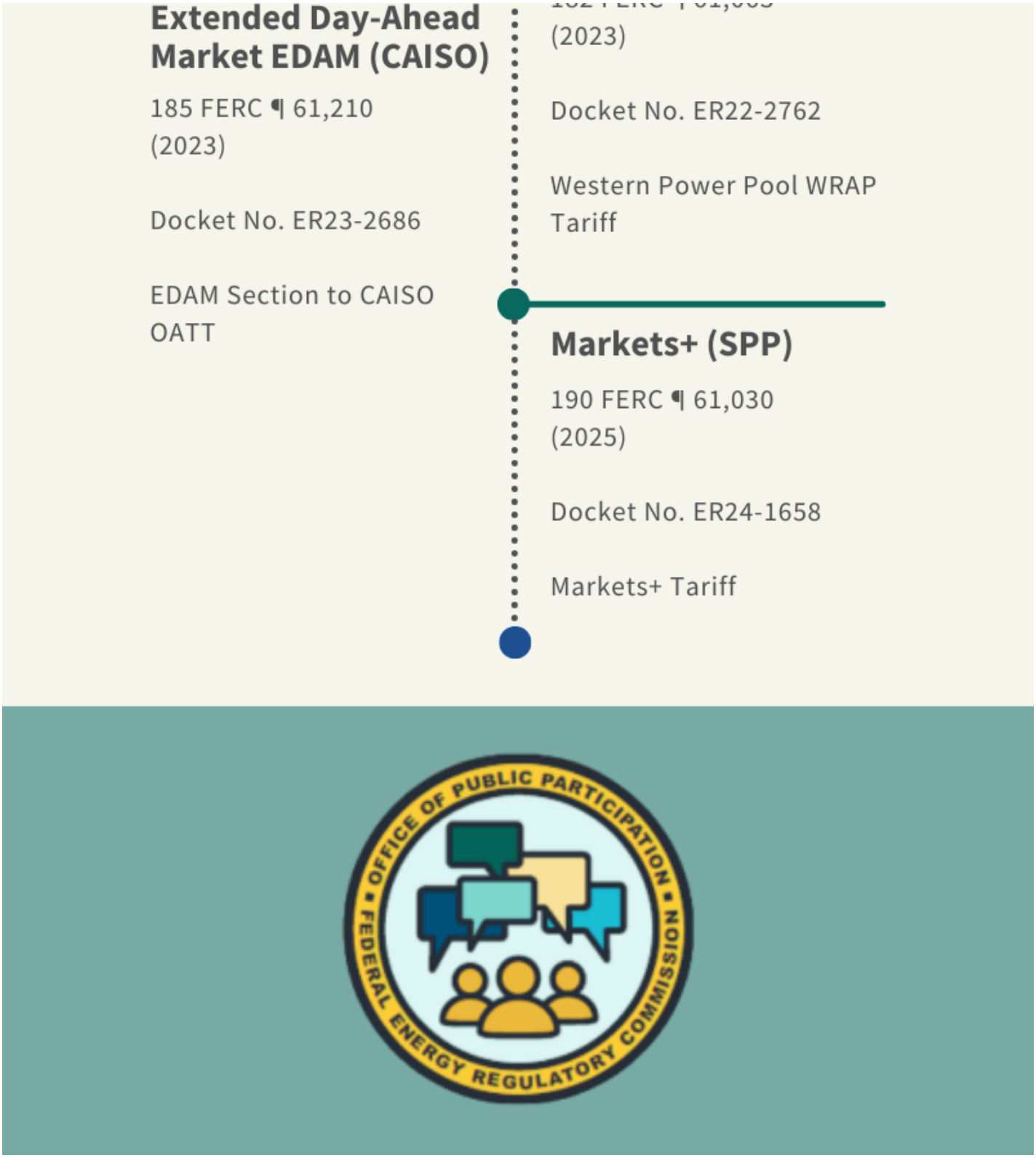


Figure 7. Western Markets Expansion infographic.

[1] Transmission Agency of Northern California. https://www.tanc.us/understanding-transmission/the-western-us-power-system.

[2] Specifically, FERC mandated NERC to oversee the reliability of the bulk power system, which includes parts of Mexico and Canada. For further information, see the Office of Public

Participation's Reliability Primer. https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[3] Electricity Markets Explainer. https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission.

[4] Order 2000 can be viewed at: https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

[5] Electric Power Markets. https://www.ferc.gov/electric-power-markets.

[6] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[7] In the case of CAISO, the ISO has chosen not to seek RTO status. RTOs are electric power transmission system operators that coordinate, control, and monitor a multistate electric grid. ISOs are like RTOs, which also coordinate, control, and monitor the operation of the electrical power system. However, ISOs cover geographic areas within a state or a smaller region.

[8] Understanding and Participating in CAISO Processes. https://www.ferc.gov/understanding-and-participating-california-iso-caiso-processes.

[9] CAISO. http://www.caiso.com/about/Pages/OurBusiness/Default.aspx.

[10] CAISO. https://www.westerneim.com/Documents/weim-first-quarter-benefits-for-2023-reach-418-million.pdf.

[11] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[12] WEIM. https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

[13] WEIM. https://www.westerneim.com/Pages/Governance/GoverningBody.aspx.

[14] SPP. https://spp.org/western-services-documents/?id=371676.

[15] SPP. https://spp.org/documents/61046/wmec%20charter%2020221018.pdf.

[16] SPP. https://spp.org/western-services/weis/.

[17] Western Power Pool. https://www.westernpowerpool.org/private-media/documents/WPP_WRAP_Interoperability_with_Markets_June_2023.pdf.

[18] Western Power Pool. https://www.westernpowerpool.org/.

[19] CAISO. https://www.caiso.com/Documents/Resource-Adequacy-Fact-Sheet.pdf.

[20] *Northwest Power Pool*, 182 FERC 61,063 at P 13-14 (2023).

[21] Western Power Pool. https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

Quick Links

- Introduction to Western Markets Expansion

Contact Information

Office of Public Participation (OPP)
Telephone: 202-502-6595
Email: OPP@ferc.gov

This page was last updated on April 18, 2025

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	)

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

Exhibit 2-145:
Western Pool Reserve Sharing Program

NWPP RSG
POWERED BY WPP

Northwest Power Pool
Reserve Sharing Program Documentation

NWPP Reserve Sharing Program 1.18.2006
RSG Committee Approved, effective: 10.1.2025

NWPP Reserve Sharing Documentation

TABLE OF CONTENTS

NWPP Reserve Sharing Program

A. INTRODUCTION AND OVERVIEW 6
B. KEY TERMINOLOGY 8
C. OVERVIEW OF KEY RESERVE SHARING PROGRAM ELEMENTS 13
C.1. How Much Contingency Reserve a Participating Balancing Authority Must Carry (Contingency Reserve Obligation) 13
C.2. When a Participating Balancing Authority May Deploy Contingency Reserve and Request Assistance Reserve (Qualifying Events) 13
C.3. What a Participating Balancing Authority Must Do Before Requesting Assistance Reserve 13
C.4. Where to Find Additional Information on Participant Eligibility and Obligations 14
D. RESERVE REQUIREMENTS 14
D.1. How NWPP Reserve Sharing Program Rules Relate to BAL-002 14
D.2. Contingency Reserve Obligations and Associated Requirements Related to WECC Operating Reserve - Supplemental 15
D.3. Additional Policies Governing Contingency Reserve 15
D.4. Additional Operating Reserve: Obligations Under R3 and R4 of WECC BAL-002-WECC-3 and Compliance Documentation 19
E. REQUESTING ASSISTANCE RESERVE 20
E.1. Qualifying Events 20
E.2. Action Required Before Requesting Assistance Reserve 20
E.3. Timing of Requests for Assistance Reserve 21
E.4. Performance Metric 22
E.5. Accounting for Energy; Transmission for Delivery 22
E.6. Restoring Reserves 22
F. OBLIGATION TO PROVIDE ASSISTANCE RESERVE 23
G. ELIGIBILITY FOR AND PARTICIPATION IN RESERVE SHARING PROGRAM 23

G.1. Eligibility to Participate in the NWPP Reserve Sharing Program 23
G.2. Treatment of Third-Party Generation 24
H. ROLES AND RESPONSIBILITIES 24
H.1. Participant Responsibilities 24
H.2. WPP Staff Monitoring and Reporting Responsibilities 25
H.3. RSG Committee Reporting Responsibilities 26
I. GENERAL DATA REQUIREMENTS 26
I.1. Data Telemetered from Participating Balancing Authorities to the Reserve Sharing Computer System 26
I.2. Cut Planes 28
I.3 Functions of the Reserve Sharing Computer System 28
I.4. Data Telemetered from the Reserve Sharing Computer System to Participating Balancing Authorities 29
I.5. Informational Data Telemetered from the Reserve Sharing Computer System to the Reliability Coordinators 32
J. DATA REQUIREMENTS RELATED TO RESERVE SHARING REQUESTS 33
J.1. Requesting Participant 33
J.2. Responding Participants 34
K. SETTLEMENT 35
K.1. Settlement Data 35
K.2. Financial Settlement 36
L. INTERNAL NWPP RESERVE SHARING GROUP REPORTING 38
L.1 Obligation to Submit a NWPP RSG Verification Form 38
L.2 Reporting Balancing Authority Obligation to Notify WPP Staff 39
M. RESERVE SHARING ZONES 39
N. BACKUP PROCEDURES 40
O. PROCEDURES FOR ADDRESSING ISSUES AFFECTING RESERVE SHARING PROGRAM WHEN AGENCY AGREEMENT PROCESS IS INSUFFICIENT 40
P. PENALTIES FOR NON-PERFORMANCE (Effective July 1, 2024) 41
P.1 Grading 41
P.2 Edge Case Events Review and Final Determination 42

P.3 Penalties 42

P.4 Reset 44

ATTACHMENTS

Attachment A – Calculation of Contingency Reserve Obligation; Requirements Related to WECC Operating Reserve - Supplemental 46

Attachment B – Qualifying Events..... 57

Attachment C – Reserve Sharing Zone and Levels 59

Attachment D – NWPP Process Charts..... 63

Attachment E – Backup Procedures for NWPP Reserve Sharing Program 68

Attachment F – Transmission Mapping and Tag Template Change Process 72

Attachment G – Backup Process for ATF Reserve Sharing Tags..... 74

Attachment H – Balancing Authority Areas of Participating Balancing Authorities 76

Attachment I – Reserved for Future Use..... 78

Attachment J – Reserved for Future Use 79

Attachment K – Northwest Power Pool Reserve Sharing Group Tables for Typical Planning MSSC in Real Time, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multiuse Transformer(s)..... 80

Attachment L – Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones..... 89

Attachment M – Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE 91

Attachment N – Correlation Table of Participants, Reliability Coordinators, and Reserve Sharing Zones..... 93

DOCUMENTATION HISTORY 95

NWPP Reserve Sharing Program

A. INTRODUCTION AND OVERVIEW

Standards established by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) require all Balancing Authorities to carry reserve for defined categories of contingencies. As permitted by NERC and WECC standards, Participating Balancing Authorities within the Northwest Power Pool (NWPP) have instituted the NWPP Reserve Sharing Program for Contingency Reserve.

By sharing Contingency Reserve, Participants are entitled to use not only their own "internal" reserve resources, but to call on other Participants for assistance if internal reserve does not fully cover a contingency. Except when communication links are down or the Reserve Sharing Computer System is not functioning, the NWPP Reserve Sharing Program is automated, operating through direct communication of data and Contingency Reserve deployment signals between the Reserve Sharing Computer System and the Participating Balancing Authorities. The WPP Staff is responsible for preparing and submitting required NERC and WECC compliance reports, and responding to compliance audits, on behalf of the NWPP Reserve Sharing Group for BAL-002. Participants are relieved of BAL-002 compliance reporting obligations, and do not report to NERC or WECC on BAL-002 compliance individually.

This document describes how the NWPP Reserve Sharing Program works. It covers:

- key terminology for the NWPP Reserve Sharing Program (Section B),
- an overview of the key elements of the NWPP Reserve Sharing Program (Section C),
- how much Contingency Reserve each participant is required to carry (Attachment A),
- what events allow participants to deploy their own Contingency Reserve, and, if necessary, request assistance reserve, how a participant may request assistance reserve from other participants (Attachment B and Section E),
- participants' obligations to supply assistance reserve (Section F),
- eligibility to participate in reserve sharing and how eligible Balancing Authorities become participants (Section G),
- the roles and responsibilities of participants, the WPP Staff, and others (Section H),
- general data requirements and the functions of the reserve sharing computer system (Section I),
- data requirements related to requests for assistance reserve (Section J),
- how participants settle when assistance reserve is supplied under the NWPP Reserve Sharing Program (Section K and Attachment D),

- tracking and reporting procedures related to the NWPP Reserve Sharing Program (Section L),
- identification of "zones" within the NWPP Reserve Sharing Group for delivering reserve energy, and the sequence in which assistance reserve from adjacent zones is deployed if the assistance reserve inside a given zone is insufficient to meet a contingency (Section M and Attachment C);
- backup procedures participants will use if the communication links that enable automated reserve sharing go down (Section N and Attachment E);
- procedures for addressing issues that affect the NWPP Reserve Sharing Program when the process under the *Agreement Appointing Agent and Establishing Responsibilities Related to Reserve Sharing Group Compliance with BAL-002* is insufficient (Section O);
- an explanation of why the NWPP Reserve Sharing Group does not activate Contingency Reserve during operation of BPA remedial action schemes that are designed to suspend automatic generation control (Attachment M),

This document includes several attachments, some of which have been noted above. The full set of attachments and their titles are as follows:

Attachment A – Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

Attachment B – Qualifying Events

Attachment C – Reserve Sharing Zone and Levels

Attachment D – Process Chart

Attachment E – Backup Procedures for NWPP Reserve Sharing Program

Attachment F – Transmission Mapping and Tag Template Change Process

Attachment G – Backup Process for After-the-Fact Reserve Sharing Tags

Attachment H – Balancing Authority Areas of Participating Balancing Authorities

Attachment I – *Reserved for Future Use*

Attachment J – *Reserved for Future Use*

Attachment K – Typical Planning MSSC in Real Time, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multi Use Transformer(s) Tables

Attachment L – Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

Attachment M – Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Attachment N – Correlation Table of Participants, Reliability Coordinators, and Zones

B. KEY TERMINOLOGY

The terms identified below have the meanings given to them in this document for purposes of the NWPP Reserve Sharing Program. Most terms defined by NERC or the WECC are conformed to the NERC or WECC definitions, but some terms' definitions may not be identical to those established by NERC or the WECC.

ACE: Area Control Error, as defined in the NERC Glossary.

Actual Net Interchange (NI_A): Actual Net Interchange, as defined in the NERC Glossary.

Agency Agreement: The *Agreement Appointing Agent and Establishing Responsibilities Related to Reserve Sharing Group Compliance with BAL-002*, as initially effective on July 1, 2008, together with any subsequent amendments or restatements.

Assistance Reserve: Contingency Reserve of one Participant that is delivered to another Participant in response to a Reserve Sharing Request.

BAL-002: For the RSG, BAL-002 means:

- NERC Reliability Standards BAL-002 and BAL-002-WECC
- And with respect to a Participant, those provisions of the foregoing (or any substantially similar standard) applicable to the Participant by law or regulation.

Balancing Authority (BA): Balancing Authority, as defined in the NERC Glossary.

Balancing Authority Area (BAA): Balancing Authority Area, as defined in the NERC Glossary.

Balancing Authority Area MSSC: A NWPP Reserve Sharing Group Participant Balancing Authority and its Balancing Authority Area's real-time MSSC based on actual configurations and provided to the Reserve Sharing Computer System via ICCP in real time.

Balancing Contingency Event: Balancing Contingency Event, as defined in the NERC Glossary.

Contingency Event Recovery Period: Contingency Event Recovery Period, as defined in the NERC Glossary.

Contingency Reserve: Contingency Reserve, as defined in the NERC Glossary.

Contingency Reserve Available (CRA): Contingency Reserve committed by a Participating Balancing Authority, which the Participating Balancing Authority reports to the Reserve Sharing Computer Program, that:

- is fully deployable within ten minutes for use as Internal Reserve (except for amounts reported as already deployed for Qualifying Events);
- is fully deployable within ten minutes of an Assistance Reserve Sharing Request for delivery (except for amounts reported as already deployed for Qualifying Events); and
- is sustainable for 60 minutes from the time of a request for Assistance Reserves.

Subject to the foregoing requirements, a Participating Balancing Authority's Contingency Reserve Available:

- will, for monitoring purposes, be deemed to include a Participant's Contingency Reserve reported as available for deployment; and
- may include Contingency Reserve purchased or otherwise transferred to the Participating Balancing Authority. Reporting ACE transferred from one Participant to another Balancing Authority Area would be considered a transfer; and
    - if arranged from another entity from outside of the Participant's zone (as detailed in Attachment C) and deployed for a valid request, details of deployment shall be reported to the WPP Staff.
- may include load committed to be shed for Contingency Reserve if a Participant is in an EEA; and
- must exclude Contingency Reserve the Participating Balancing Authority has sold to any other party.

A Participating Balancing Authority's Contingency Reserve Available plus amounts reported as Used for internal Qualifying Events and the amount deployed in response to a request for Assistance Reserves must be equal to or greater than its Contingency Reserve Obligation.

Contingency Reserve Obligation (CRO): As specified in Attachment A to this document, Contingency Reserve Obligation is the minimum amount of Contingency Reserve that must be carried by a particular Participant for its Balancing Authority Area(s) or by the NWPP Reserve Sharing Group as a whole (as the context requires) to respond to Qualifying Events. Although the acronym "CRO," as used in this document, may sometimes designate base calculation of a Participating Balancing Authority's Contingency Reserve Obligation (before adjustments described in Attachment A), the written term "Contingency Reserve Obligation"

as used in this document refers to the total amount of Contingency Reserve that must be carried for a Participant's Balancing Authority Area(s) (or the NWPP Reserve Sharing Group as a whole), taking into account all applicable adjustments specified in Attachment A.

Firm Demand: Firm Demand, as defined in the NERC Glossary.

Internal Reserve: The Contingency Reserve of a Participating Balancing Authority when deployed to respond to a Qualifying Event on the Participating Balancing Authority's own system (as opposed to Contingency Reserve delivered as Assistance Reserve to another Participating Balancing Authority).

Long-Term Zonal MSSC Limit: An identified normal system MSSC documented in Attachment K.1. by each zone's Participant Balancing Authority/Balancing Authority Areas.

Most Severe Single Contingency (MSSC): The Most Severe Single Contingency, as defined in the NERC Glossary.

NERC Glossary: The NERC Glossary of Terms Used in Reliability Standards.

North American Electric Reliability Corporation (NERC): A self-regulatory nonprofit organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada, whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces reliability standards, assesses reliability annually via 10-year and seasonal forecasts, monitors the bulk power system, and educates, trains, and certifies industry personnel.

Northwest Power Pool (NWPP): The geographic area encompassed by the electric systems of the NWPP Agreement Signatories. There is also a separate corporation named "Northwest Power Pool," which provides staffing and other resources to support implementation of the NWPP Agreement. In general, when this document refers to the Northwest Power Pool or the NWPP, it is referring to the geographic area and the associated electric power systems of the NWPP Agreement Signatories.

NWPP Agreement: A multilateral agreement to promote cooperation among participating organizations to achieve reliable operation, coordinate generation operation and power system planning, and assist in planning of transmission within the NWPP area.

NWPP Agreement Signatory (Signatory): An entity that is a party to the NWPP Agreement.

NWPP Reserve Sharing Group: The group composed of all Participants, collectively.

NWPP Reserve Sharing Group Long-Term MSSC Limit: The identified long-term maximum limit of the NWPP Reserve Sharing Group's MSSC is the largest Long-Term Zonal MSSC Limit as documented in Attachment K.1.

NWPP Reserve Sharing Group Reporting ACE: The algebraic sum of the Reporting ACE of the Participant(s) experiencing the RBCE (or multiple BCEs occurring within 60 seconds) and the Reporting ACE of those Participant(s) delivering Assistance Reserve to the Requesting Participant(s) -see Attachment C "Reserve Sharing Zones and Levels", including any Participant delivering transferred Assistance Reserve.

NWPP Reserve Sharing Program: The procedures, data, computer programs, and related information and requirements described in this document that enable Participants to request and provide Assistance Reserve as needed to respond to Qualifying Events.

Operating Plan: Operating Plan, as defined in the NERC Glossary.

Operating Process: Operating Process, as defined in the NERC Glossary.

Operating Reserve: Operating Reserve, as defined in the NERC Glossary.

Participating Balancing Authority or Participant: An entity that (a) operates one or more Balancing Authority Areas and (b) has become a participant in the NWPP Reserve Sharing Program as described in Section G.1. The terms "Participant" and "Participating Balancing Authority" are used interchangeably in this document. Attachment H contains a list of the Balancing Authority Areas of the current Participating Balancing Authorities.

Qualifying Event: Those events designated in Attachment B of this document as Qualifying Events.

Recovery Reporting ACE Target: The average value of a requesting Participant's Reporting ACE in the 16-second interval immediately prior to the start of the Qualifying Event (or zero, whichever is less) or the average value of a Participant's Reporting ACE that is providing Assistance Reserve in the 16-second interval immediately prior to the request of Assistance Reserves (or zero, whichever is less) based on EMS scan rate data.

Reliability Coordinator (RC): Any one or more organizations performing the NERC-registered function (or its equivalent in Canada) of reliability coordination within the Northwest Power Pool.

Reportable Balancing Contingency Event: Reportable Balancing Contingency Event, as defined in the NERC Glossary.

Reporting ACE: Reporting ACE, as defined in the NERC Glossary.

Reserve Sharing Computer System: The software and hardware used for automated reserve sharing under the NWPP Reserve Sharing Program.

Reserve Sharing Request: A request by Participating Balancing Authority that has satisfied the conditions specified in Section E.2 for delivery of Assistance Reserve.

Reserve Sharing Zone: A designated set of Balancing Authority Area(s) within the Reserve Sharing Group that is separated from other Balancing Authority Area(s) within the Reserve Sharing Group by transmission facilities that have been shown through studies to constrain reserve deliveries, at times, between the designated set and the other Balancing Authority Areas. Attachment C to this document identifies the Reserve Sharing Zones that have been established for the NWPP Reserve Sharing Program, together with the sequence through which Assistance Reserve is deployed for each Reserve Sharing Zone.

RSG Committee: The committee established under the terms of the NWPP Agreement to administer the NWPP Reserve Sharing Program.

Scheduled Net Interchange (NI_S): Scheduled Net Interchange, as defined in the NERC Glossary.

System Operator: System Operator, as defined in the NERC Glossary.

Third-Party Generation: Any generating resource that is within the metered boundaries of the Balancing Authority Area of a Participating Balancing Authority but is neither owned by nor under contract to that Participating Balancing Authority.

WECC Soft Price Cap: The price cap adopted by the Federal Energy Regulatory Commission in *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services*, 93 FERC ¶ 61,121 (2000) and *Western Electric Coordinating Council*, 133 FERC ¶ 61,026 (2010), subject to the guidance provided by the Federal Energy Regulatory Commission in *ConocoPhillips Company, et al*., 175 FERC ¶ 61,226 (2021)

WECC Operating Reserve - Supplemental: WECC Operating Reserve - Supplemental is the portion of Operating Reserve consisting of:

- generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Contingency Event Recovery Period following a contingency event; or
- load fully removable from the system within the Contingency Event Recovery Period following the contingency event;

provided, however, that for purposes of the NWPP Reserve Sharing Program (as required by WECC Standard BAL-002-WECC-3), WECC Operating Reserve - Supplemental must also be:

- capable of fully responding within ten minutes.

Western Electricity Coordinating Council (WECC): A nonprofit corporation with the mission to foster and promote reliability and efficient coordination in the Western Interconnection.

WPP Staff: The employees of the Northwest Power Pool Corporation doing business as the Western Power Pool.

C. OVERVIEW OF KEY RESERVE SHARING PROGRAM ELEMENTS

C.1. How Much Contingency Reserve a Participating Balancing Authority Must Carry (Contingency Reserve Obligation)

The processes for calculating how much Contingency Reserve each Participant must carry for its Balancing Authority Area(s), and the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, are set forth in Attachment A to this document along with the process chart as reflected in Attachment D.

C.2. When a Participating Balancing Authority May Deploy Contingency Reserve and Request Assistance Reserve (Qualifying Events)

A Participating Balancing Authority must experience a "Qualifying Event" before it is entitled to deploy any portion of its Contingency Reserve Obligation (as Internal Reserve) or request Assistance Reserve. The definition of Qualifying Event is set forth in Attachment B to this document.

C.3. What a Participating Balancing Authority Must Do Before Requesting Assistance Reserve

A Participating Balancing Authority must fully commit an amount of its Balancing Authority Area's Internal Reserve that equals or exceeds the requesting Participant's CRO requirement to the NWPP before requesting Assistance Reserve to respond to a Qualifying Event. This requirement is more fully explained in Section E.2 of this document. There are also requirements concerning the timing and duration of Assistance Reserve Sharing Requests, which are set forth in Section E.3.

C.4. Where to Find Additional Information on Participant Eligibility and Obligations

Eligibility

Provisions governing eligibility to participate in the NWPP Reserve Sharing Program are in Section G of this document.

Additional Operating Reserve for R3 and R4 of WECC BAL-002-WECC-3

Section D.4 describes Participating Balancing Authorities' obligations to enable the NWPP Reserve Sharing Group to demonstrate compliance with Sections R3 and R4 of BAL-002-WECC-3.

Data Obligations

Section I contains information on the data requirements for the general operation of the NWPP Reserve Sharing Program, as well the functions of the Reserve Sharing Computer System. Section J describes data requirements for making and responding to Reserve Sharing Requests.

Providing Assistance Reserve

Participants' obligations to provide Assistance Reserve are explained in Section F.

Restoring Contingency Reserve Following Deployment

Section E.6 describes Participants' obligations to restore their Contingency Reserve following deployment (either as Internal Reserve or Assistance Reserve).

D. RESERVE REQUIREMENTS

D.1. How NWPP Reserve Sharing Program Rules Relate to BAL-002

The NWPP Reserve Sharing Program is intended to enable the NWPP Reserve Sharing Group to comply with BAL-002, as well as certain additional rules the NWPP Reserve Sharing Group has elected to adopt for itself.

Participants are required at all times to meet the requirements of BAL-002, as revised, supplemented, or superseded from time to time in accordance with applicable NERC, WECC, or regulatory procedures. BAL-002 constitutes the foundation on which the NWPP Reserve Sharing Group rules are built. Compliance with the NWPP Reserve Sharing Group rules for Contingency Reserve is intended to ensure compliance with the BAL-002, but cannot serve to excuse any compliance failure related to the NERC or WECC standards.

NERC Standard BAL-002-3 requires Balancing Authorities (or reserve sharing groups) to recover, within the Contingency Event Recovery Period, from Reportable Balancing Contingency Events (subject to certain exceptions).

WECC Standard BAL-002-WECC-3 governs Contingency Reserve, but also includes requirements (set forth in Sections R3 and R4 of BAL-002-WECC-3) for additional Operating Reserve that must be carried by Participants engaging in certain types of transactions involving purchases from units supplying Contingency Reserve or sales of Operating Reserve. This document addresses, at Section D.4, requirements for Participating Balancing Authorities to enable the NWPP Reserve Sharing Group to demonstrate compliance with Sections R3 and R4 of BAL-002-WECC-3.

D.2. Contingency Reserve Obligations and Associated Requirements Related to WECC Operating Reserve - Supplemental

Section 1 of Attachment A to this document provides a detailed explanation of how to calculate the Contingency Reserve Obligation for each Participating Balancing Authority. Section 1 also explains the manner in which the Participating Balancing Authorities' Contingency Reserve Obligations are combined to yield an aggregate obligation for the NWPP Reserve Sharing Group. Section 2 of Attachment A specifies what portion of Participating Balancing Authorities' Contingency Reserve Obligations must be carried as permitted sources of WECC Operating Reserve - Supplemental. Every Participating Balancing Authority must include in its operating procedures provisions that require it to:

a. maintain and have available an amount of Contingency Reserve Available that is equal to or greater than its Contingency Reserve Obligation,

b. perform such calculations as may be necessary (including consideration of transmission constraints) to ensure that it can deploy Contingency Reserve reported as available, and

c. deploy its Contingency Reserve Available for Qualifying Events as provided in this document.

Section 3 explains the Participating Balancing Authorities calculation of Contingency Reserve Obligation(s) when communications with the Reserve Sharing Computer System are disrupted.

D.3. Additional Policies Governing Contingency Reserve

a. <u>No Double Counting</u>

As expressed in the policies of the RSG Committee, multiple Participants may not count the same portion of resource capacity (*e.g.,* reserves from jointly owned generation) toward any portion of their Contingency Reserve Obligations, and the NWPP Reserve Sharing Group rules do not permit this.

b. <u>Contingency Reserve Available</u>

All Participants must continuously calculate and update their Contingency Reserve Available. A Participating Balancing Authority's Contingency

Reserve Available plus amounts reported as Used for internal Qualifying Events and the amount deployed in response to a request for Assistance Reserves must be equal to or greater than its Contingency Reserve Obligation.

c. Purchased Power

To provide flexibility in recovering from a Qualifying Event, any Participant may use power purchased from another Participant (or another supplier) to meet its Contingency Reserve Obligation. Any Participant that uses purchased power for recovery must report the source Balancing Authority(s) of the purchased power, the time the power was purchased, the start time and ramp rate for the mutually agreed-upon purchased power (or transaction). The WPP Staff will be responsible for determining whether a Participant providing purchased power fulfilled its obligations to deploy Contingency Reserve to enable the NWPP Reserve Sharing Group to comply with BAL-002. The requesting Participant must also arrange for transmission for delivery of the power. If the Balancing Authority from which the power was purchased is not a Participant in the NWPP Reserve Sharing Program, then any failure of the selling Balancing Authority to deliver the purchased power will be deemed, for purposes of the NWPP Reserve Sharing Program, as a failure to deliver of the Participant relying on the purchased power.

d. Aggregate Contingency Reserve Available

The aggregate Contingency Reserve Available for the NWPP Reserve Sharing Group (together with any Contingency Reserve deployed for Qualifying Events) must at all times equal or exceed both the NWPP Reserve Sharing Group's Most Severe Single Contingency and its combined Contingency Reserve Obligation.

e. RSG Committee Responsibilities; Monitoring and Follow-Up

The RSG Committee is responsible for developing guidelines and arranging for periodic reporting of the Contingency Reserve Obligation of the NWPP Reserve Sharing Group and the Contingency Reserve Available within the NWPP Reserve Sharing Group. WPP Staff monitors Participants' compliance with Contingency Reserve Obligations. The RSG Committee is responsible for addressing problems with deficient or poorly performing Participants, for developing remedies and proposed solutions, and for identifying and implementing any follow-up actions.

f. Determination of NWPP Reserve Sharing Group's Most Severe Single

Contingency

Each Participant is responsible for (i) determining, based on appropriate system modeling and applicable NERC definitions and guidelines, the Most Severe Single Contingency for its Balancing Authority Area(s), (ii) reporting its Most Severe Single Contingency determinations to the WPP Staff and making sure they are correctly reflected in Attachment K, and (iii) notifying WPP Staff whenever previously submitted Most Severe Single Contingency determinations need to be updated. The Most Severe Single Contingency for the NWPP Reserve Sharing Group at any given time is set by whichever of the Participants' Most Severe Single Contingencies is greatest at that time. The RSG Committee will review, at each of its meetings (and in any event no less than once a year), the NWPP Reserve Sharing Group's Operating Processes and its Most Severe Single Contingency to ensure the BAA MSSC's in Attachment K and other applicable tables are up to date and comply with applicable NERC and WECC requirements.

g. Participants' Monitoring of Real-Time Most Severe Single Contingencies

Every Participant is responsible for determining and telemetering to the Reserve Sharing Computer System, as provided in Section I.1.g, its Most Severe Single Contingency (and any adjustments upward or downward) based on real-time operating conditions. When determining Most Severe Single Contingencies in real time, each Participant must take into account its real-time generation output and its real-time generation and transmission outages. Real-time adjustments to a Participant's Most Severe Single Contingency should be captured and updated every data scan cycle.

h. All Participants' Contingency Reserve Available Constitutes NWPP Reserve Sharing Program Contingency Reserve Available

The amount of Contingency Reserve carried by the Participants to meet the requirements of NERC, WECC, and the NWPP Reserve Sharing Program is calculated so as to meet the needs of the NWPP Reserve Sharing Group as a whole and the Contingency Reserve Available reported by each Participant is deemed to be Contingency Reserve Available to the NWPP Reserve Sharing Program. Accordingly, if any Participant activates a portion of its Contingency Reserve to respond to a Qualifying Event, this will constitute activation of a portion of NWPP Reserve Sharing Program Contingency Reserve, including for purposes of calculating whether the Qualifying Event constitutes a Reportable Balancing Contingency Event, even if the activation of Contingency Reserve is not for a Reportable Balancing Contingency Event and even if the affected Participant does not

make a Reserve Sharing Request. Any Qualifying Event affecting any Participant constitutes a Qualifying Event for the NWPP Reserve Sharing Group, and therefore, unless at the time of the Qualifying Event the affected Participant is in "non-participating" status, recovery from the Qualifying Event will be determined with respect to the NWPP Reserve Sharing Group as a whole, and not the individual Participant.

i. Participant Obligation to Respond to Reportable Balancing Contingency Events

A Participant that has experienced a Qualifying Event (within its Balancing Authority Area):

- shall recover its ACE within the 15-minute Contingency Event Recovery Period for any loss greater than 50 MW, and
- must, if the Qualifying Event is equal to or greater than the threshold for Reportable Balancing Contingency Events, take all commercially reasonable actions that are necessary, in its good-faith judgment, to enable the NWPP Reserve Sharing Group to recover its Reporting ACE according to the requirements of BAL-002. To fulfill this obligation, the Participant is expected, among other things, to (i) deploy its Contingency Reserve, and (ii) if the Participant meets the conditions specified in Section E.2 and cannot fully recover from the Qualifying Event with reserve capability on its own system (and any purchased reserve rights), make a Reserve Sharing Request.

For Qualifying Events that result from the loss of a jointly owned facility, affected Participants must use the total MW of facility output lost to determine whether the Qualifying Event is equal to or greater than the threshold for Reportable Balancing Contingency Events (rather than whatever portion of the lost output a given Participant may have scheduled or been entitled to).

j. NWPP Reserve Sharing Program Automation and Exceptions.

Every Participant is always in active status with respect to the Reserve Sharing Program. All Participants must continuously and automatically telemeter to the Reserve Sharing Computer System the data specified in Section I.1, (unless unable to do so due to failure of communications capabilities between the Participant and the Reserve Sharing Computer System). Every Participant must also indicate (unless unable to do so) whether its participation is through automatic or manual capabilities. Valid reasons for Participants to indicate manual participation mode include, but are not limited to: failure of inter-control center

communications protocol (ICCP) links, suspension of automatic generation control (AGC), and system testing.

D.4. Additional Operating Reserve: Obligations Under R3 and R4 of WECC BAL-002-WECC-3 and Compliance Documentation

a. Participants Must Carry Required Additional Operating Reserve

Each Participating Balancing Authority must carry, in addition to its Contingency Reserve Obligation calculated in accordance with Attachment A, sufficient Operating Reserve to fulfill the requirements of R3 and R4 of BAL-002-WECC-3.

b. Participants Must Maintain and Provide Documentation to Demonstrate Compliance

Each Participating Balancing Authority must maintain appropriate documentation for any periods during which it has implemented

- any Interchange Transactions (as that term is defined by NERC) (i) with counterparties that are not Participants, (ii) for which it was the sink Balancing Authority, and (iii) that were designated as part of the source Balancing Authority's WECC Operating Reserve - Supplemental; or
- any Operating Reserve transactions (x) with counterparties that are not Participants, and (y) for which it was the source Balancing Authority.

The Participating Balancing Authority's documentation must be sufficient to demonstrate that, during all relevant periods, it maintained additional Operating Reserve as required by R3 and R4 of BAL-002-WECC-3.

Each Participating Balancing Authority must, on at least a quarterly basis, submit summaries to the WPP Staff of transactions subject to R3 and R4 of BAL-002-WECC-3, in the form specified by the WPP Staff (in consultation with the Participating Balancing Authorities). Participating Balancing Authorities that prefer to submit this information to the WPP Staff on a more frequent basis (including through the Reserve Sharing Computer System in real-time) may do so in coordination with the WPP Staff.

In addition, all Participating Balancing Authorities must supply copies of supporting documentation to the NWPP Reserve Sharing Group (or the WPP Staff) promptly upon request.

c. Deployment of Additional Operating Reserve Not Restricted to Qualifying Events

Because the additional Operating Reserve necessary to comply with R3 and R4 of BAL-002-WECC-3 is incremental to Participants' Contingency Reserve Obligations, Participants are not limited in their use of this additional Operating Reserve to Qualifying Events. Participants are entitled to deploy this additional Operating Reserve to respond to interruption of Interchange Transactions (as described in BAL-002-WECC-3 R3) or fulfillment of Operating Reserve transactions (as described in BAL-002-WECC-3 R4) even if these do not constitute Qualifying Events.

E. REQUESTING ASSISTANCE RESERVE

E.1. Qualifying Events

The Qualifying Events that permit Participants to deploy Internal Reserve, and, if the conditions specified in Section E.2 are satisfied, request Assistance Reserve, are specified in Attachment B to this document.

E.2. Action Required Before Requesting Assistance Reserve

If a Participant experiences a Qualifying Event (Attachment B parts A, B, or C), the requesting Participant is entitled to request and schedule Assistance Reserve (up to the amount lost minus their Contingency Reserve Obligation to fully recover from the Qualifying Event) through the NWPP Reserve Sharing Program **only** after the requesting Participant has made commitments to use an amount of Internal Reserve that equals or exceeds the requesting Participant's Contingency Reserve Obligation. A Participant experiencing a Qualifying Event from Attachment B part D is entitled to request Assistance Reserve to meet Firm Demand as necessary after committing to use ALL Internal Reserve. At the time of the Participant's request for Assistance Reserve, the fulfillment of the Participant's obligation to fully commit its Contingency Reserve Obligation will be evaluated taking into account any Internal Reserve lost because of the Qualifying Event (such as the loss of a generator on which reserve was being carried, whether due to conditions affecting the generator itself or due to loss of generator interconnection or transmission facilities necessary for delivery of output from the generator). The amount of Contingency Reserve carried by any unit that is lost due to the Qualifying Event will be considered deployed and added to the used Contingency Reserve reported.

If the requesting Participant improperly reflects their UsedCR less than their $TotCRO_{CA}$, the program will reduce the amount of Assistance Reserves provided (not including any rounding that occurs programmatically) by the amount that UsedCR is less than $TotCRO_{CA}$.

a. Response to an Energy Emergency Alert 3

A Participant may utilize Contingency Reserve to respond to an Energy Emergency Alert 3 (EEA 3), as described in Attachment B, Section D.

If time allows, the Participant will notify the Western Power Pool staff on the 24/7 support line 503.673.6744 of the situation, which will enable the staff to provide any clarification that may be needed.

E.3. Timing of Requests for Assistance Reserve

After experiencing a Qualifying Event as described in Attachment B parts A, B, or C and fulfilling the conditions specified in Section E.2, a Participant that requires Assistance Reserve may submit a Reserve Sharing Request, however, must do so within 60 minutes following the start of the Qualifying Event. Reserve Sharing Requests must be made in whole MWs.

Even though an eligible Participant may make a Reserve Sharing Request at any time within 60 minutes following that start of a Qualifying Event, the NWPP Reserve Sharing Group may, with respect to administering the terms of the Agency Agreement, differentiate between Reserve Sharing Requests submitted promptly—that is, within four minutes following the start of the Qualifying Event—and Reserve Sharing Requests that are delayed beyond four minutes. The "four-minute rule" does not affect Participants' obligations to deliver Assistance Reserve to other Participants that have made Reserve Sharing Requests, which, as stated in Section F, applies to all Reserve Sharing Requests made within 60 minutes following the start of the Qualifying Event.

If (a) a Reserve Sharing Request is made more than four minutes following the start of the Qualifying Event, and (b) the NWPP Reserve Sharing Group's Reporting ACE does not recover from the Qualifying Event within the applicable Contingency Event Recovery Period, then for purposes of any potential compliance consequences associated with the Qualifying Event, the matter will be addressed in accordance with Sections 7.2, 7.3, 8, and 9 of the Agency Agreement.

A Participant that has made a Reserve Sharing Request may rely on Assistance Reserve for a maximum period of 60 minutes from the time of the Qualifying Event.

The Qualifying Event outlined in Attachment B part D, allows for a request to be made at any time during the declared EEA 3 instead of immediately upon declaration of the EEA 3. An Assistance Reserve Request made for an EEA 3 allows the Participant to receive Assistance Reserve for up to 60 minutes from the time of the initial request. Subsequent hours of an EEA 3 are not additional Qualifying Events. If a participant is out of a declared EEA 3 for more than one hour before another EEA 3 is declared that next EEA 3 declaration will be considered a new Qualifying Event.

If another Qualifying Event occurs, it is a separate event, and the Participant may make an additional request for Assistance Reserve.

E.4. Performance Metric

Deployment of Contingency Reserve by a Participant requesting Assistance Reserve will be measured through evaluation of the Participant's Pre-Reporting Contingency Event ACE through the following criteria:

- In the first fifteen-minute period after the disturbance occurs, the Participant's Reporting ACE must be above their Recovery Reporting ACE Target for at least one scan; and
- Within nineteen minutes after the disturbance occurs and after the initial Reporting ACE recovery, the Participant's Reporting ACE must stay at or above their Recovery Reporting ACE Target minus 25% of their individual BAA's L_{10} value (as published by NERC) for at least five clock-minute average periods.
- If the request is not made within the required 4-minute period after the start of the Qualifying Event, the entity will be deemed to have not performed to the requirements of the program.

E.5. Accounting for Energy; Transmission for Delivery

Any Participant that requests Assistance Reserve must complete a NWPP RSG Verification Form and must account for scheduled receipt and delivery of Assistance Reserve energy as "Contingency Reserve." Tagging of Energy with respect to deliveries of Assistance Reserve energy is implemented as described in Section K.1.c. of this document.

The delivery of Assistance Reserve is exempt from any costs or charges associated with transmission wheeling or losses. The Reserve Sharing Computer System builds in sufficient transmission capacity for delivering Assistance Reserve (see Section M). There may be incremental transmission usage between some Reserve Sharing Zones, but this usage is effectively limited in real-time up to the current System Operating Limit (SOL) of the transmission facilities making up the cut planes between Reserve Sharing Zones (subject to certain further limitations with respect to particular cut planes as described the *NWPP RSG Cut Planes and Derivation Limits* document). Participants in the NWPP Reserve Sharing Program recognize the regional benefits associated with the NWPP Reserve Sharing Program and have agreed to waive any rights to financial settlement for any transmission needed to deliver Assistance Reserve to other Participants.

E.6. Restoring Reserves

If a Participant uses any portion of its Contingency Reserve Obligation in response to a Qualifying Event (whether use is limited to Internal Reserve or requires additional Assistance Reserve), the Participant should take appropriate action to restore Contingency Reserve Available on its system (to at least the level of its Contingency Reserve Obligation) as promptly as practicable. A Participant may not take longer than 60 minutes (measured from the start of the Qualifying Event) to restore Contingency Reserve Available on its system to at least the level of its

Contingency Reserve Obligation.

F. OBLIGATION TO PROVIDE ASSISTANCE RESERVE

Each Participant is obligated to deliver Assistance Reserve up to the full amount of its Balancing Authority Area's Contingency Reserve Obligation (after deducting for any capacity that has been deployed to respond to any Qualifying Events) in response to any Reserve Sharing Request that has met the requirements in Section E.2 and is made within 60 minutes following the start of the Qualifying Event.

Deployment of Contingency Reserve by a Participant providing Assistance Reserves will be measured through evaluation of the Participant's Reporting ACE through the following criteria:

- In the first ten-minute period after the request for Assistance Reserve, or any increase thereof, is received, the Participant's Reporting ACE must be above their Recovery Reporting ACE Target for at least one scan; and
- Within fifteen minutes of the request for Assistance Reserves and after the initial Reporting ACE recovery, the Participant's Reporting ACE must stay at or above their Recovery Reporting ACE Target minus 25% of their individual BAA's L_{10} value (as published by NERC) for at least five clock-minute average periods.

If a Participant has deployed all or a portion of its Balancing Authority Area's Contingency Reserve Obligation to respond to a Reserve Sharing Request by another Participant and then, while the deployment is still in effect, experiences its own Qualifying Event, the responding Participant may deploy whatever portion of its Contingency Reserve Obligation is required to recover from its own Qualifying Event. If the conditions necessary to receive Assistance Reserve are satisfied, the Participant may also make a Reserve Sharing Request even if one or more other Participants' Reserve Sharing Requests remain in effect. If the NWPP Reserve Sharing Group experiences sequential Qualifying Events that require one or more responding Participants to deploy Assistance Reserve that was being provided to other Participants, the Reserve Sharing Computer System will recalculate the distribution of Assistance Reserve and allocate to remaining Participants any amount necessary to replace the deployed Assistance Reserve.

G. ELIGIBILITY FOR AND PARTICIPATION IN RESERVE SHARING PROGRAM

G.1. Eligibility to Participate in the NWPP Reserve Sharing Program

All Balancing Authorities that operate Balancing Authority Areas located within the Northwest Power Pool and that elect to become NWPP Agreement Signatories must participate in the NWPP Reserve Sharing Program and must become parties to the Agency Agreement.

G.2. Treatment of Third-Party Generation

Each Participating Balancing Authority must, in calculating its Contingency Reserve Obligation, include all generation that is within its metered boundaries and for which the Participating Balancing Authority has an obligation or has agreed to provide Contingency Reserve. The term "Qualifying Event" with respect to a Participating Balancing Authority applies to any generation (including Third-Party Generation) that has been included in that Participating Balancing Authority's calculation of its Contingency Reserve Obligation.

H. ROLES AND RESPONSIBILITIES

H.1. Participant Responsibilities

Participants are responsible for abiding by the NWPP Reserve Sharing Group rules specified in this document, together with any corresponding policies adopted by the RSG Committee. These include requirements to meet Contingency Reserve Obligations, to provide Assistance Reserve when requested by another Participant, and to settle for deliveries of Assistance Reserve energy as provided in Section K.
Participants must also provide and receive data for the NWPP Reserve Sharing Program in accordance with Section I for general operation of the NWPP Reserve Sharing Program and Section J for making and responding to requests for Assistance Reserve.

a. Notifications

Participants must notify the WPP Staff and the NWPP Reserve Sharing Group Committee whenever a substantive change to the Participant's Balancing Authority Area is planned to occur. This would include, at a minimum, a change in Balancing Authority Area footprint or boundary, transfer of load or generation with another Balancing Authority Area, or any change that could have an impact to the deliverability of contingency reserves or the MSSC within the Participant's zone. This notification should occur prior to any changes being made to allow adequate time for appropriate impact studies to be completed and Program Document or computer program modifications, as needed.

The Participating Balancing Authorities are responsible to provide planned system failover notifications that may have an impact to data being telemetered to the Reserve Sharing Computer System to WPP Staff via an email to nwpprsg@westernpowerpool.org.

b. Program Monitoring

In addition, the Participating Balancing Authorities are responsible to monitor the NWPP Reserve Sharing Group "heartbeat" (as explained in Section I.1.n). If any Participating Balancing Authority discovers the NWPP Reserve Sharing Group heartbeat is inactive for a period of 10 minutes they should contact an adjacent Participating Balancing Authority to confirm this is a system-wide problem and not just a problem with their system or communication link. If the problem is believed to be system-wide that Participating Balancing Authority will contact the WPP Staff.

If a Participating Balancing Authority's heartbeat appears to be inactive at the time it needs to make a Reserve Sharing Request, it should initiate the Reserve Sharing Request as described in Attachment E – *Backup Procedures for NWPP Reserve Sharing Program*.

It is all Participating Balancing Authorities' responsibility to inform all other Participating Balancing Authorities and the WPP Staff if they have discovered a problem. In addition, Participating Balancing Authority System Operators and RSG Committee Representatives can e-mail or call with any questions or issues. WPP Staff will respond as soon as possible.

NWPP Reserve Sharing Group Program Support Contact Information:

- For immediate response the on-call support number at 503.673.6744.
- In addition, for non-urgent issues, you may email "nwpprsg@westernpowerpool.org". WPP Staff will respond to after-hours emails the next business day during normal work hours.

H.2. WPP Staff Monitoring and Reporting Responsibilities

The WPP Staff is responsible for monitoring Participants' compliance with Contingency Reserve Obligations. The RSG Committee is responsible for addressing problems related to Participant deficiencies or poor performance, for developing remedies and presenting proposed solutions, and for identifying and implementing any follow-up actions.

The WPP Staff is responsible for receiving NWPP RSG Verification Forms from Participants that have made Reserve Sharing Requests under the NWPP Reserve Sharing Program. The WPP Staff will perform analysis on each Reportable Balancing Contingency Event that the NWPP Reserve Sharing Group experiences with relationship to Participant's adherence to the Program Rules.

Subject to appropriate confidentiality and use restrictions (as determined by the WPP Staff), the WPP Staff may make available, to a Participant hosting implementation of an ACE Diversity Interchange arrangement, data related to the NWPP Reserve Sharing Program for the purpose of enabling the hosting Participant to harmonize the operation of the NWPP Reserve Sharing Program and the implementation of the ACE Diversity Interchange arrangement.

WPP Staff is responsible for monitoring and assisting in the implementation of the NWPP Reserve Sharing Program. While not staffed 24x7, WPP Staff will provide on-call 24x7 support as may be required. Although Participants are responsible for telemetering data to the Reserve Sharing Computer System as described in Sections I.1, and I.2, if WPP Staff notices missing information, WPP Staff will follow up with the affected Participant(s).

WPP Staff can review the status of each of the individual Participating Balancing Authority's data including heartbeats. If a WPP Staff member discovers a Participating Balancing Authority's heartbeat is inactive, he or she will follow up with the affected Participating Balancing Authority and document any findings by e-mail to all Participating Balancing Authorities.

H.3. RSG Committee Reporting Responsibilities

The RSG Committee is responsible for developing guidelines and arranging for periodic reports on the Contingency Reserve Obligation of the NWPP Reserve Sharing Group and Contingency Reserve Available within the NWPP Reserve Sharing Group as a whole.

I. GENERAL DATA REQUIREMENTS

This section describes data responsibilities for Participants in the NWPP Reserve Sharing Program. Although in general all required data are relayed automatically to the Reserve Sharing Computer System, all Participants must also have the capability to enter data manually if communications between Participating Balancing Authorities and the Reserve Sharing Computer System are interrupted.

I.1. Data Telemetered from Participating Balancing Authorities to the Reserve Sharing Computer System

Each Participant must telemeter the following data to the Reserve Sharing Computer System for each of its Balancing Authority Areas within the Northwest Power Pool:

a. the portion of its Contingency Reserve Available that is WECC Operating Reserve - Spinning ($TotCSR_{CA}$) ready for use as Internal Reserve or Assistance Reserve,

b. total Contingency Reserve Available ($TotAvailCR_{CA}$) ready for use as Internal Reserve or Assistance Reserve,

c. its total Balancing Authority Area Load (LOAD), as used to calculate its Contingency Reserve Obligation (CRO_{CA}) in accordance with Attachment A,

d. its total Balancing Authority Area Generation (GEN), as used to calculate its Contingency Reserve Obligation (CRO_{CA}) in accordance with Attachment A,

e. any portion of its reported Contingency Reserve Available already in use ($UsedCR_{CA}$),

f. its Reporting ACE (ACE_{raw}), as calculated according to the NERC glossary of terms,

g. its Most Severe Single Contingency ($MSSC_{CA}$),

h. Scheduled Net Interchange values (NET_SCHED_INT), as used to calculate an equivalent ACE,

i. Actual Net Interchange values (NET_ACTUAL_INT), as used to calculate an equivalent ACE,

j. its Reserve Sharing Request dynamic schedule ($RSReq_{CA}$),

k. request for Reserve Sharing Status Indication ($RSReq\_Confirmd_{CA}$)

No Request = Status Open

Assistance Requested = Status Closed,

l. reserve sharing response (RSResp),

m. indication (manually entered) of availability to provide Assistance Reserve (Participating Balancing Authorities not available to provide Assistance Reserve can still receive Assistance Reserve) (BA_Participate)

Cannot Provide Assistance Reserve = Status Open

Can Provide Assistance Reserve = Status Closed,

n. status of the communications links that enable it to participate in the NWPP Reserve Sharing Program on an automated basis, also known as its “heartbeat” (signaled by continuing changes to indicator data not to exceed 999,999, which the Reserve Sharing Computer System monitors at 10-second intervals; if there is no change to the data for a period of 60 seconds, the Participating Balancing Authority is presumed to be able to participate in the NWPP Reserve Sharing Program only through manual action; when the indicator data begin to change again, the Participating Balancing Authority is presumed to have regained the ability to participate in the NWPP Reserve Sharing Program through automated action) (BA_heart_beat), and

o. its frequency bias setting. (BA_FBS)

p. its meter error term (BA_Ime)

q. its ATEC term (BA_ATEC)

r. its ADI term if not included in Scheduled Net Interchange or Actual Net Interchange values above (BA_ADI)

I.2. Cut Planes

Explanatory note: As used in this Section I.2, the term "cut plane" is intended generally to describe an imaginary line separating two areas within a transmission system (or two different transmission systems) to enable the evaluation of flow of electrical energy on multiple lines connecting these two areas (or systems). The cut planes referred to below are sets of multiple lines connecting Reserve Sharing Zones.

Participants that are operators of the major transfer facilities must telemeter to the Reserve Sharing Computer System actual flow ($ACTUAL_{PATHnn}$) and transfer limit ($LIMIT_{PATHnn}$) for each direction of flow for the cut planes, as identified in Attachment L, between Reserve Sharing Zones as described in the next Section I.3.e.

The RSG Committee maintains a separate document, *NWPP RSG Cut Planes and Derivation Limits*, that more fully details the major transfer facilities and any associated Participant derivation information, including applicable calculations for which the Participant that monitors that cut plane, address the evaluation of flow of electrical energy on multiple lines.

I.3 Functions of the Reserve Sharing Computer System

Except when communications links or the necessary computer capabilities are down, the Reserve Sharing Computer System performs the tasks listed below. WPP Staff is able to monitor the Reserve Sharing Computer System and receive all Participants' data described in Sections I.1 and I.2. If WPP Staff notices that there is missing information, WPP Staff will consult directly with any Participating Balancing Authorities for which information is missing to make any necessary corrections.

a. Determine the Most Severe Single Contingency for the NWPP as a whole ($MSSC_{NWPP}$).

b. Determine the aggregate Contingency Reserve Obligation for the NWPP as a whole ($TotCRO_{NWPP}$) to ensure that the Contingency Reserve Available within the NWPP Reserve Sharing Group is sufficient to cover the Contingency Reserve Obligation for the NWPP as a whole.

c. Determine the Contingency Reserve Obligation ($TotCRO_{CA}$) for each Participant's Balancing Authority Area(s), calculated in accordance with Attachment A.

d. Compute a pro rata allocation of any applicable adjustments to Contingency Reserve Obligations ($AdjCRO\_MSSC_{CA}$ and $AdjCRO\_ZONE\_MSSC_{CA}$, which together are summed into $AdjCRO_{CA}$) for each Participant's Balancing Authority Area(s) to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.

e. In calculating any potential need to carry additional Contingency Reserve within a Reserve Sharing Zone, take into account transfer limits ($LIMIT_{Pathnn}$), actual flows ($ACTUAL_{Pathnn}$), and, where applicable, scheduled flows ($SCHED_{Pathnn}$) on

the transmission facilities connecting that Reserve Sharing Zone to its adjacent Reserve Sharing Zone(s). With respect to the facilities linking the Pacific Northwest-Montana Reserve Sharing Zone with the Northern California Reserve Sharing Zone, this also reflects limits on ownership rights.

f. Maintain a pro rata allocation of the Reserve Sharing delivery dynamic schedule based upon each $TotCRO_{CA}$ for each Participant's Balancing Authority Area(s) relative to the $TotCRO_{NWPP}$.

g. Upon receipt of a Reserve Sharing Request dynamic schedule from a Participating Balancing Authority that is requesting Assistance Reserve, validate and activate the pro rata sharing signal to all other Participating Balancing Authorities.

h. Whenever Assistance Reserve is being delivered across facilities connecting two different Reserve Sharing Zones, continue to monitor actual flows ($ACTUAL_{Pathnn}$) in comparison to transfer limits ($LIMIT_{Pathnn}$) between the Reserve Sharing Zones, and, to the extent actual flows fall below transfer limits, allow deliveries to increase if needed to fully respond to the Reserve Sharing Request.

i. Maintain hourly integrated Reserve Sharing Request dynamic schedules from each Participating Balancing Authority.

j. Calculate a NWPP Reserve Sharing Group ACE (TOTACE_POOL) for entire NWPP Reserve Sharing Group.

k. Calculate a NWPP Reserve Sharing Group Reporting ACE for each Requesting Zone and Level 1 (or Level 2 for NCAL) Participants (ZONEACE_XXX – See Attachment C).

Each Participating Balancing Authority should consistently review the Contingency Reserve Obligation (CRO_{CA}) value transmitted to it by the Reserve Sharing Computer System to confirm the accuracy of the calculation and should promptly contact WPP Staff if it suspects there may be an error in the Reserve Sharing Computer System's calculation.

I.4. Data Telemetered from the Reserve Sharing Computer System to Participating Balancing Authorities

The Reserve Sharing Computer System makes available to each Participant the following telemetered data:

a. The Reserve Sharing Computer System's calculation of total Contingency Reserve Obligation ($TotCRO_{CA}$) for the Participant's Balancing Authority Area(s), as described in Attachment A. This includes, as applicable,

- calculation of base Contingency Reserve Obligation based on three percent of load and three percent of generation (CRO_{CA}),

- any adjustment to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group (AdjCRO_MSSC$_{CA}$),
- any adjustment to address shortages within a particular Reserve Sharing Zone (AdjCRO_ZONE_MSSC$_{CA}$), and
- combined adjustments to Contingency Reserve Obligation (AdjCRO$_{CA}$) to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.
- total Contingency Reserve Obligation (TotCRO$_{CA}$) as adjusted to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.

b. If the total Contingency Reserve Available within the NWPP Reserve Sharing Group (TotAvailCR$_{NWPP}$) is less than to total Contingency Reserve Obligation for the NWPP Reserve Sharing Group (TotCRO$_{NWPP}$), the NWPP Reserve Sharing Computer System calculates and telemeters necessary adjustments to total Contingency Reserve Obligation (TotCRO$_{CA}$) for each Participant's Balancing Authority Area(s) to reflect the shortfall in total Contingency Reserve Available within the NWPP Reserve Sharing Group (AdjCRO_SHORT$_{CA}$). Each Participant must carry this adjustment amount in addition to its TotCRO$_{CA}$.

c. If a Participant is in the penalty level 4 status, a flag (TBD) will be set by WPP Staff to communicate to the program and to the Participant that they are required to carry additional Contingency Reserves.

d. Reserve Sharing Delivery dynamic schedule (RSDel) for Participating Balancing Authority that is delivering Assistance Reserve:[1]

RSDel$_{CA(Level\ 1)}$ = RSReq$_{CA}$ * (TotCRO$_{CA}$ / S TotCRO$_{CA(Level\ 1)}$), limited to the portion of its Contingency Reserve Obligation (TotCRO$_{CA}$), if any, the Participating Balancing Authority is able to deliver at that time (after accounting for any portion of its TotCRO$_{CA}$ previously deployed)

Where,

RSReq$_{CA}$ £ MW$_{LOSS}$ - TotCRO$_{CA}$

- If S RSDel$_{CA(Level\ 1)}$ < RSReq$_{CA}$, then

[1] (All "$_{CA}$" designations in these formulas refer to the particular Participating Balancing Authority to which a given value applies. References to "Levels" are to the Levels related to the Reserve Sharing Zones, as identified in Attachment C.)

$RSReq_{Short} = RSReq_{CA} - S\ RSDel_{CA(Level\ 1)}$

and,

$RSDel_{CA(Level\ 2)} = RSReq_{Short} * (TotCRO_{CA} / S\ TotCRO_{CA(Level\ 2)})$.

- If the amount of Assistance Reserve that can be delivered from the Participating Balancing Authorities at Level 2 is insufficient to meet whatever portion of the Reserve Sharing Request remains after deliveries from Participating Balancing Authorities at Level 1, the process is repeated as described above for Level 3, and, if applicable, Level 4 and Level 5.
- If there are multiple requests for Assistance Reserve, the $RSDel_{CA}$ would be calculated to reflect the sum of all amounts to be delivered as Assistance Reserve to requesting Participants, but the Reserve Sharing Computer System separately tracks the amounts to be delivered to each of the requesting Balancing Authorities (so that payment and return energy obligations can be properly determined).
- Requests for Assistance Reserve are not allowed to exceed the Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole.
- Transmission constraints are included the Reserve Sharing Computer System's calculation of how much Assistance Reserve can be delivered from each Level for each Reserve Sharing Zone, and so do not need to be separately computed and applied.

e. Delivery of Reserve Sharing Confirmation Flag ($RSDel\_Confirmd_{CA}$),

No Request = Status Open

Assistance Requested = Status Closed

f. Reserve Sharing time remaining for the requesting Balancing Authority from the most recent request for Assistance Reserve (TimeLeft)

g. Number of active Reserve Sharing Requests (RSAct)

h. The MSSC for the NWPP Reserve Sharing Group as a whole ($MSSC_{NWPP}$)

i. The Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole ($TotCRO_{NWPP}$)

j. The Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole ($TotAvailCR_{NWPP}$)

k. NWPP Reserve Sharing Group Reporting ACE (ACE_{NWPP})

l. Reportable Balancing Contingency Event (RpDist)

Where,

RpDist = the lesser of (a) 0.8 * $MSSC_{NWPP}$ or 500 MW

m. Total number of minutes remaining since the most recent request for the NWPP (RSTimRem)

n. The indication that the Reserve Sharing Computer System and associated communication links are operational is also known as the NWPP Reserve Sharing Group "heartbeat."

o. When activity on the Reserve Sharing Computer System is due to testing rather than power system conditions, this is indicated by a testing flag. WPP Staff will arrange for this flag to be set while testing is underway, which may include helping a Participating Balancing Authority test its system(s). (The NWPP Reserve Sharing Program is fully operational while testing is in progress and Reserve Sharing Requests may be made normally. If there is a Reserve Sharing Request during testing, the test will be terminated.)

p. The Reserve Sharing Computer System's calculation for each Reserve Sharing Zone as reflected in Attachment C,

- The MSSC ($MSSC_{zone}$)
- The total Contingency Reserve within the zone ($TOTCR_{zone}$),
- Calculation of the zonal Contingency Reserve Obligation based on the zonal Participant(s) three percent of load and three percent of generation ($TOTCRO_{zone}$),
- The total Contingency Reserve Available to the zone ($TOTCRA_{zone}$),

q. The Reserve Sharing Computer System's information or calculation for each cut plane between Reserve Sharing Zones as reflected in in Section I.2.

- The actual flow ($ACTUAL_{PATHnn}$) and transfer limit ($LIMIT_{PATHnn}$) for each direction of flow
- The actual room ($ROOM_{PATHnn}$) and reserve ($RESERVE_{PATHnn}$) for each direction of flow

I.5. Informational Data Telemetered from the Reserve Sharing Computer System to the Reliability Coordinators

The Reserve Sharing Computer System telemeters to the Reliability Coordinators the following informational data:

a. The MSSC for the NWPP Reserve Sharing Group as a whole ($MSSC_{NWPP}$),

b. The Reserve Sharing Group Reporting ACE (ACE_{NWPP}),

c. The Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole ($TotCRO_{NWPP}$), and

d. The Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole ($TotAvailCR_{NWPP}$).

e. Data for each of the Reserve Sharing Zones as follows:
- The MSSC for the Reserve Sharing Zone,
- The Contingency Reserve Obligation for the Reserve Sharing Zone, and
- The Contingency Reserve Available for the Reserve Sharing Zone.

Attachment N is a correlation table of Participants, Reliability Coordinators, and Reserve Sharing Zones.

J. DATA REQUIREMENTS RELATED TO RESERVE SHARING REQUESTS

The general data requirements for Participants in the NWPP Reserve Sharing Program are described in Section I. The provisions below explain the steps for making and responding to Reserve Sharing Requests.

J.1. Requesting Participant

a. A Participant that has met the conditions to make a Reserve Sharing Request (as described in Section E.2) must calculate the amount of Assistance Reserve for which it is eligible, enter the deficient amount needed into a Reserve Sharing Request dynamic schedule, and send the request, at a zero-ramp span time, to the Reserve Sharing Computer System.

Where,

$RSReq_{CA}$ £ MW_{LOSS} – $TotCRO_{CA}$

RqstRSSI = 1.

At this point in time, the Participant's anticipated CR_{CA} should be zero if their CR_{CA} was equal to $TotCRO_{CA}$. If CR_{CA} was higher than $TotCRO_{CA}$, CR_{CA} should decrease by the amount shown as $UsedCR_{CA}$.

$TotCRO_{CA} – UsedCR_{CA} \leq 0$

c. Requesting Participants are expected to restore the Contingency Reserve Available on their systems, to at least the level of their Contingency Reserve Obligations, as promptly as practicable, but in no event longer than 60 minutes from the start of the Qualifying Event.

d. As a safeguard, the Reserve Sharing Computer System will remove the Reserve Sharing Request dynamic schedule within 65 minutes following the Reserve Sharing Request.

   $RSReq_{CA}$ = 0, ten-minute ramp to zero beginning at 55 minutes after the request first started.

   RqstRSSI = 0

e. If during the request the Requesting Participant detects a Reserve Sharing Computer System failure, it should assume that the Responding Participants will continue to deliver reserves for the full 65 minutes as called for in J.1.d.

f. If a Participant makes a Reserve Sharing Request for an initial Qualifying Event and, before the end of the 60 minutes during which the Participant is allowed to rely on Assistance Reserve (as provided in Section E.3 of this document), experiences one or more additional Qualifying Events for which it wishes to request Assistance Reserve, the Participant may initiate additional Reserve Sharing Requests by (1) activating the additional Reserve Sharing Request toggle on the Reserve Sharing Computer System (which indicates that the requesting Participant has two or more active Reserve Sharing Requests), then (2) revising the deficient amount needed, as calculated in accordance with Section J.1.a above, to include the additional amount of Assistance Reserve required for the additional Qualifying Event(s). The activation of any additional Reserve Sharing Request will re-set the overall event timer to 65 minutes (the permitted 60-minute reliance period plus an additional five minutes to complete ramping). While the Reserve Sharing Computer System continues to run separate event timers for each Qualifying Event, Participants are able to see only the time remaining for a Participant's last-initiated Reserve Sharing Request, and not for any of its previously initiated Reserve Sharing Requests.

J.2. Responding Participants

a. Responding Participants should initiate a response to a Reserve Sharing Delivery dynamic schedule from the Reserve Sharing Computer System by including $RSDel_{CA}$ in their ACE equation shown below. A security check on the Reserve Sharing Request dynamic schedule includes a crosscheck such that Reserve Sharing Status Indication = 1. The sign of the $RSDel_{CA}$ is negative for Participating Balancing Authorities requesting Assistance Reserve. The sign of the $RSDel_{CA}$ is positive for Participating Balancing Authorities providing Assistance Reserve.

   Where,

   $ACE_{CA} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$

   NI_S = S(adjacent Balancing Authority schedules) + S(dynamic schedules) + $RSDel_{CA}$

Each responding Participant will maintain an internal timer equal to $TotTmRem_{NWPP}$ and continue to count down this timer to zero if the value from the Reserve Sharing Computer System fails to decrement (indicating probable loss of data link). Whenever a responding Participant is operating in an assumed disconnected mode, $RSDel_{CA}$ is internally frozen. When the internal count-down timer reaches zero, the responding Participant should set $RSDel_{CA}$ to zero.

K. SETTLEMENT

A Participant that receives Assistance Reserve energy must compensate all Participants that deliver Assistance Reserve energy financially.

Participants may mutually agree to an alternate procedure, provided the affected Participants can account for the transaction appropriately.

This section explains how the data used for settlement is developed and the process through which Participants complete financial settlement. Attachment D includes a settlement process chart as reference of this process.

K.1. Settlement Data

Each hour, whether or not there has been a Reserve Sharing Request, the Reserve Sharing Computer System will transmit the hour-ending integrated dynamic schedule quantities (MWh) to all Participating Balancing Authorities. These data will be referred to as "Settlement Data" and will include source/sink energy information without consideration of transmission "wheeling" through intervening systems. Settlement Data are rounded and used to develop adjacent Balancing Authority interchange schedules. Settlement Data will be used to construct the official reserve sharing energy matrix (the "Matrix").

a. Rounding

Settlement Data are rounded to whole integers to accommodate scheduling and accounting systems:

- All Settlement Data quantities less than 1 MWh will be rounded to 0 MWh (e.g., 0.7 yields 0 MWh). This practice will reduce nuisance scheduling of small quantities.

- For quantities equal to or greater than 1 MWh, conventional rounding practices will apply. Fractional quantities less than 0.5 will be rounded down (*e.g.*, 27.2 yields 27 MWh) and fractional quantities of 0.5 or greater will be rounded up (*e.g.*, 27.9 yields 28 MWh). After rounding, Settlement Data are compiled into the matrix.

b. Mapping of Energy Schedules

Energy schedules must be mapped to adjacent Balancing Authorities to allow proper energy accounting consistent with existing reliability standards and regional business practices. The Participants have agreed to a pre-defined set of tag templates to account for the transmission mapping for the deliveries of Assistance Reserve Energy. This mapping includes wheeling parties between nonadjacent Balancing Authorities, and as further explained in Section K.1.c below, serves as the basis to create after-the-fact tags.

c. Automatic Tagging and Tag Templates

The Participants' tag templates reflect the transmission mapping for the delivery of Assistance Reserve energy between Participating Balancing Authorities. The Northwest Power Pool Corporation has a contract with Open Access Technology International, Inc. (OATI) to produce after-the-fact energy schedule tags for all deliveries of Assistance Reserve energy. These tags are provided to the Participants and the WECC Western Interchange Tool (WIT).

The WPP Staff is responsible for assisting with the maintenance of these tag templates used by OATI, and keeping them up-to-date in accordance with requests made by Participating Balancing Authorities. Attachment F describes the NWPP Reserve Sharing Group's procedures for revising the transmission mapping as reflected in the tag templates.

The Participants' tag templates are not publicly available and are only accessible to the RSG Representatives, their designated RSG Alternate Representatives and tagging personnel. The designated representatives may access and download the most current version of *NWPP RSG Tagging Templates.xls* on the Western Power Pool website (www.westernpowerpool.org) in the Reserve Sharing Group's Documents.

K.2. Financial Settlement

The NWPP Reserve Sharing Group utilizes the Intercontinental Exchange (ICE) day-ahead peak and off-peak index prices at the Mid-Columbia (Mid-C) and Palo Verde (PV) trading hubs, for the calculation of the settlement price as noted in subsection (a.) below.

A Participant will be financially reimbursed for providing Assistance Reserve energy.

For purposes of the NWPP Reserve Sharing Program, the "Settlement Price" for peak hours will be the average of the ICE day-ahead peak index prices for the Mid-C and PV trading hubs. The "Settlement Price" for off-peak hours will be the average of the ICE day-ahead off-peak index prices for the Mid-C and PV trading hubs, *provided, however*, that (a) if ICE does not publish a Day-Ahead Price for a relevant operating day or Request Hour, then the Settlement Price shall be the average of the other Day-Head Price for the Request Hour and (b) in no event will the Settlement

Price ($/MWh) be less than zero or greater than the WECC Soft Price Cap in accordance with regulations and orders of the Federal Energy Regulatory Commission (FERC).

Examples of settlement for 10 MWh of dispatched energy:

Example 1:
Index prices: Mid-C $50, PV $75
Calculation: ($50+$75)/2 = $62.50 settlement price x 10MWh = $625

Example 2:
Index prices: Mid-C $50, PV-No Trade.
Calculation: $50+ (excluded) = $50 settlement price x 10MWh = $500

Example 3:
Index prices: Mid-C $-20 (below price cap), PV $5,
Calculation: ($0 + $5)/2 = $2.50 Settlement Price x 10MWh = $25

Example 4:
Index prices: Mid-C $1035 (above WECC Soft Energy Price Cap), PV $750,
Calculation: ($1,000 + $750)/2 = $875*10MWh = $8,750

With respect to FERC-jurisdictional entities, the Settlement Price will be set forth in the Participant's individual tariff on file with and approved by FERC. In the event that the Settlement Price set forth in a. above is amended, such amended Settlement Price will not be effective until all FERC-jurisdictional entities have approved amended tariffs.

During the RSG Committee's third quarter meeting the RSG Committee (or a work group or task force appointed by the RSG Committee) will review the definition of "Settlement Price," to ensure the selected trading hubs and applicable day-ahead peak and off-peak index price continue to represent a fair value of energy within the NWPP Reserve Sharing Group footprint. The RSG Committee may elect to either maintain the current definition of "Settlement Price" or propose a modified definition to be considered for approval at the next meeting of the RSG Committee. The effective date of any modification to the definition of "Settlement Price" will be coordinated to allow Participants with applicable tariffs filed with FERC to make any necessary filings with FERC.

Unless the affected Participants have agreed otherwise, financial settlements will occur under the responding Participant's normal monthly billing cycle.

WPP Staff will be responsible for determining and posting Settlement Prices, calculated as described in subsection (a) above of this Section K.3, in accordance with the following procedures:

a. WPP Staff will use the day-ahead peak and off-peak prices posted by ICE at the end of each trading day to programmatically calculate and post the Settlement Price for all hours of the days for which prices were published (operating days).

b. In the first three (U.S.) business days following the first (U.S.) business day of each month (referred to in these procedures as the "lock down date"), WPP Staff may confer with designated Participants for assistance in validating the applicable prices posted by ICE for the preceding month and the computation of the Settlement Prices as necessary.

c. By the end of the third (U.S.) business day following the lock-down date, WPP Staff will post finalized Settlement Prices for all hours of the preceding month, computed as described in this subsection (e).

d. If, as of the lock-down date, information needed to compute one or more Settlement Prices has not yet been posted by ICE, WPP Staff will compute and post Settlement Prices for those applicable dates and hours within three (U.S.) business days following the date on which the necessary information is first posted by ICE.

e. Settlement Prices that have been posted by WPP Staff in accordance with the procedures set forth above will not be subject to further adjustment, except by agreement of all affected Participants.

L. INTERNAL NWPP RESERVE SHARING GROUP REPORTING

L.1 Obligation to Submit a NWPP RSG Verification Form

A Participant must, within two (U.S.) business days following the triggering event, prepare and submit to the WPP Staff a completed NWPP RSG Verification Form whenever any one of four conditions described below occurs:

a. The Participant makes a Reserve Sharing Request under the NWPP Reserve Sharing Program (including use of backup procedures specified in Section N if the automated process fails).

b. The Participant or the NWPP Reserve Sharing Group has experienced a Qualifying Event that is a Reportable Balancing Contingency Event (equal to or greater than the lesser of (i) 500 MW, or (ii) 80% of the Most Severe Single Contingency) for the NWPP Reserve Sharing Group at the time of the Qualifying Event.

c. The WPP Staff contacts the Participant requesting a NWPP RSG Verification Form because the Participant has ownership or contractual rights in a jointly owned facility and the WPP Staff is following up with the Participant as described in Section L.2.

d. The Participant has experienced a Reliability Coordinator declared Energy Emergency Alert (as described in NERC Standard EOP-011 or successor standard).

NWPP RSG Verification Forms are available on the WPP Website. The Participants will transmit completed forms via e-mail to nwpprsg@westernpowerpool.org. The Western Power Pool Corporation, in its capacity as agent for the NWPP Reserve Sharing Group, may request additional data and information as may be required and is responsible for submitting periodic reports to the WECC and NERC in accordance with their requirements.

L.2 Reporting Balancing Authority Obligation to Notify WPP Staff

A Participant that is the Reporting/Operating Balancing Authority (as specified in Attachment K) for a jointly owned facility must, as soon as feasible, but in any case within two (U.S.) business days following the triggering event, provide written notice to the WPP Staff (which may be by electronic mail) whenever the jointly owned facility for which it is the Reporting/Operating Balancing Authority has experienced a Qualifying Event that is a Reportable Balancing Contingency Event (equal to or greater than the lesser of (a) 500 MW, or (b) 80% of the Most Severe Single Contingency) for the NWPP Reserve Sharing Group at the time of the Qualifying Event.

The WPP Staff will promptly follow up with all other Participants that have ownership or contractual rights in the jointly owned facility to request that those Participants submit completed NWPP RSG Verification Forms.

M. RESERVE SHARING ZONES

The NWPP Reserve Sharing Program takes into account the effect constrained transmission facilities can have on the ability of Participants to deliver Assistance Reserve energy to one another. When a Participating Balancing Authority (or a group of Participating Balancing Authorities) is separated from remaining Participants by constrained transmission facilities, the effect of the constraint is reflected in the establishment of Reserve Sharing Zones. Attachment C to this document identifies the Reserve Sharing Zones for the NWPP Reserve Sharing Program, together with the sequence (levels) through which Assistance Reserve is deployed for each Reserve Sharing Zone.

The Long-Term Zonal MSSC Limits account for limitations, as determined by the Participant Balancing Authority(ies) of each zone as identified in Attachment K.1.

Proposed system changes that will result in an increase to a Long-Term Zonal MSSC as identified in Attachment K, must be approved by the Balancing Authorities of the impacted zone within 120 days of system change being identified.

In addition, any proposed change to the NWPP Reserve Sharing Group Long-Term MSSC Limit as identified in Attachment K, must be approved by the NWPP Reserve Sharing Group Committee.

N. BACKUP PROCEDURES

Reserve Sharing Requests and delivery of Assistance Reserve energy are normally implemented through the Reserve Sharing Computer System. When a Participant cannot access the Reserve Sharing Computer System (or the system is inoperable), the Participant should use the manual backup procedures as reflected in Attachment D's respective process chart and described in Attachment E and to make any Reserve Sharing Requests. In these circumstances, a responding Participant is obligated to provide Assistance Reserve only up to the amount of its available transmission capacity or its Contingency Reserve Obligation, whichever is smaller. The settlement process for delivery of Assistance Reserve energy using the backup procedure is the same as for the automated reserve sharing process, except that requesting and responding Participants must agree (on a case-by-case basis) to any reserve sharing transactions instead of obtaining the information from the Reserve Sharing Computer System. This process must be in accordance with Attachment G for production of after-the-fact tags and in accordance with existing reliability standards and regional business practices.

O. PROCEDURES FOR ADDRESSING ISSUES AFFECTING RESERVE SHARING PROGRAM WHEN AGENCY AGREEMENT PROCESS IS INSUFFICIENT

To facilitate reporting and compliance activities related to NERC or WECC reliability standards that may affect the NWPP Reserve Sharing Program, the Participating Balancing Authorities have entered into the Agency Agreement. All Participating Balancing Authorities, as well as the Northwest Power Pool Corporation, are parties to the Agency Agreement. The Agency Agreement contains provisions that enable Participating Balancing Authorities to call meetings on specified prior notice and make decisions about matters concerning the Agency Agreement or the NWPP Reserve Sharing Program. Any meeting or vote under the Agency Agreement requires at least 10 days' prior notice.

If an urgent matter related to NWPP Reserve Sharing Program arises, and the WPP Staff determines in good faith that either (1) there is insufficient time to address the matter through the procedures in the Agency Agreement or (2) the matter is outside the scope of the Agency Agreement, the WPP Staff will:

- make commercially reasonable efforts to promptly deliver electronic notice of the matter to each designated contact for notice under the Agency Agreement;
- convene a meeting by telephone conference (with the option of in-person attendance at the offices of the Northwest Power Pool Corporation if feasible) of all available Participating Balancing Authorities, giving as much advance notice and facilitating attendance of as many Participating Balancing Authorities as feasible in view of any need for prompt action;

- seek input from the Participating Balancing Authorities as to what action should be taken, and, if appropriate in the judgment of the WPP Staff or requested by any Participating Balancing Authority, take a vote of the Participating Balancing Authorities (on the basis that a vote of not less than two-thirds of the Participating Balancing Authorities present at the time the vote is taken will be necessary to approve an action or decision); and
- make commercially reasonable efforts to take follow-up action consistent with the input received or results of any vote taken in accordance with this Section O.

No vote of the Participating Balancing Authorities conducted in accordance with this Section O may have the effect of (a) amending this NWPP Reserve Sharing Program documentation, (b) amending the Agency Agreement, (c) authorizing settlement of any NERC or WECC compliance-related matter that will or could cause any party to incur violation(s), monetary penalties or other legal liability (unless the party or parties incurring violation(s), monetary penalties or legal liability have given their prior written consent); or (d) restricting the ability of any party to independently exercise whatever legal or procedural rights it may have to challenge action taken by or petition an Enforcement Authority (as that term is defined in the Agency Agreement) in connection with any NERC or WECC compliance-related matter.

P. PENALTIES FOR NON-PERFORMANCE (Effective July 1, 2024)

P.1 Grading

Events will be assessed shortly after they occur to provide feedback to the involved BAAs. Official grading for events will occur once that entity reaches the evaluation threshold. An entity may fail per the defined performance metrics and receive a score greater than 0%.

The evaluation threshold is any calendar quarter that the BAA participated in ten or more events. If an entity participates in fewer than ten events in any calendar quarter, that quarter will be considered a null quarter, and the events roll over to the next calendar quarter. Once ten events are accumulated, those events and any others during that quarter, will be evaluated and scored.

Each Assistance Reserve request and response will be evaluated and scored as follows:

For a Participant requesting Assistance Reserve:

- 50% for initial ACE Recovery in the first fifteen-minute period after the disturbance, plus
- 10% for each clock-minute average period sustained above Recovery Reporting ACE Target minus 25% of their individual BAA's L10 value (as published by NERC) in the first nineteen clock-minutes after the disturbance with a maximum of 50% for five or more sustained clock-minutes.
- With a total maximum score of 100%

If the request is not made within the required 4-minute period after the start of the Qualifying Event, the score will then be reduced by 10% for each minute (or portion thereof) beyond the 4-minute period the request is delayed. The minimum score a BAA may have is 0%.

For a Participant providing Assistance Reserve:

- 50% for initial ACE recovery in the first ten-minute period after the request for Assistance Reserve, plus
- 10% for each clock-minute average period sustained above Recovery Reporting ACE Target minus 25% of the individual BAA's L_{10} value (as published by NERC) in the first fifteen clock-minutes after the request for Assistance Reserve with a maximum of 50% for five or more sustained clock-minutes.
- With a total maximum score of 100%

All events for the quarter will be individually scored and averaged together and rounded to the nearest 0.1%, to provide a total score for the quarter. If a BAA receives a score of less than 95%, they will be determined to have failed the quarter. These scores will be reported to the RSG Committee at each meeting. If the BAA does not have any events for a quarter, that quarter will be considered a null quarter and not count as a "Pass" or a "Fail".

P.2 Edge Case Events Review and Final Determination

All RSG events will be reviewed by WPP Staff. Events that are found to have characteristics making them more difficult to respond to (ex. requests where the value is changing during the analysis period or coming in and out) will be flagged for further review. Any of these events where it is later determined that there is no impact to any member's quarterly grade (Pass/Fail) will be removed from the overall calculation. Any events with an impact will be brought to the Reserve Sharing Group Committee for final determination.

If a BAA believes that an event should be removed from consideration, they may present their case to the RSG Committee during a committee meeting. The committee will then make a determination and the quarterly score will be recalculated as necessary.

P.3 Penalties

Penalties will be assessed based on how many quarters a BAA has failed. All BAA's begin at Level 0 and increase one level from their current level with a failed quarter (ex. Q1). Penalties will be analyzed in the following quarter (ex. Q2) and any level changes implemented at 0600 pacific prevailing time the first NERC scheduling day of the quarter after that (ex. Q3). For example: Q1 will be analyzed in Q2 and any level changes implemented in Q3. Decreasing levels and null quarters are addressed in section P.4.

The penalty levels are:

Level 1:

- An official letter to the Participant RSG Representative(s) notifying them of the failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee
- The Participant RSG Representative(s) will designate a Company Executive to be notified if Level 2 is reached

Level 2:

- An official letter to the designated Company Executive notifying them of the failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee

Level 3:

- An official letter to the designated Company Executive notifying them of the failure and that their BAA will be required to carry additional Contingency Reserves with an additional failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee

Level 4:

- An official letter to the designated Company Executive notifying them of the failure and that their BAA is now required to carry additional Contingency Reserves
- The BAA will be required to carry additional reserves and be limited on the events that qualify for requesting Assistance Reserves the for one Quarter.
    - The BAA will be obligated to carry the lesser of their MSSC or 150% of their regularly calculated CRO
    - The BAA will be allowed to call on Assistance Reserve only if they experience a loss greater than their increased obligation
    - During this quarter, the BAA must still respond to requests for Assistance Reserves
    - The BAA must update their EMS or other impacted IT/OT applications to reflect these changes
    - Meet all financial obligations associated with RSG membership

- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee
- While in this level, an additional failed quarter will result in that BAA(s) triggering a vote to be removed from NWPP Reserve Sharing Group by the membership.

Level 0:

- An official letter to the Participant RSG Representative(s) notifying them of the return to Level 0 Operations
- Normal Operations – no restrictions

P.4 Reset

Each quarter a BAA passes will reduce the penalty level under which they are operating. A "null quarter" will keep the BAA at the level they were at for the previous quarter unless the BAA was at Level 4 in which case the BAA would go to Level 3 until they have passed two consecutive quarters excluding null quarters.

ATTACHMENTS

Attachment A – Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

Attachment B – Qualifying Events

Attachment C – Reserve Sharing Zones and Levels

Attachment D – NWPP Process Charts

Attachment E – Backup Procedures for NWPP Reserve Sharing Program

Attachment F – Reserve Tagging Change Process

Attachment G – Backup Process for After-the-Fact Reserve Sharing Tags

Attachment H – Balancing Authority Areas of Participating Balancing Authorities

Attachment I – *Reserved for Future Use*

Attachment J – *Reserved for Future Use*

Attachment K – MSSC and Long-Term Zonal MSSC Limit, Jointly Owned Dynamic Generation Resources, and Multi Use Transformer(s) Tables

Attachment L – Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

Attachment M – Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Attachment N – Correlation Table of Participants, Reliability Coordinators, and Zones

Attachment A

Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

1. Calculation of Participating Balancing Authority Contingency Reserve Obligation

The NWPP Reserve Sharing Group has determined that the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), as well as the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, will be calculated as set forth below. The measure of the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), as well as the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, will be based on real-time measurements of load and generation, which, for compliance purposes, will be used to calculate integrated hourly averages. These integrated hourly averages will be compared to hourly averages of Contingency Reserve Available (also based on real-time measurements) to determine whether the NWPP Reserve Sharing Group's Contingency Reserve Available was sufficient to meet the requirements of BAL-002. The amount of Contingency Reserve Available within the NWPP Reserve Sharing Group for each clock hour must be equal to or greater than the NWPP Reserve Sharing Group's Contingency Reserve Obligation during that same clock hour.

As described in detail in Section 1 of this Attachment A and reflected in Attachment D's process chart for Calculation of CRO, the Reserve Sharing Computer System uses a four-step process to determine the Contingency Reserve Obligation a Participating Balancing Authority is required to meet for its Balancing Authority Area(s) under normal circumstances, using real-time measurements as described above. The Reserve Sharing Computer System completes the calculations necessary for this process (with updated real-time measurements) every data scan cycle (that is, no less frequently than every six seconds).

These calculation processes can be summarized as follows:

First, the Reserve Sharing Computer System calculates three percent of load plus three percent of generation. Next, the Reserve Sharing Computer System sums of all Participants' Contingency Reserve calculations to see whether this calculated sum is at least equal to the Most Severe Single Contingency for the NWPP Reserve Sharing Group. If it is not, the Reserve Sharing Computer System allocates, on a pro rata basis, the additional amount of Contingency Reserve necessary to cover the NWPP Reserve Sharing Group's Most Severe Single Contingency and determines the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s) as adjusted for the NWPP Reserve Sharing Group's Most Severe Single Contingency.

The third step calculates the amount of any additional Contingency Reserve that may be needed in a Reserve Sharing Zone to cover the Most Severe Single Contingency within that Reserve

Sharing Zone and determines each the Total Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), reflecting both applicable adjustments for the NWPP Reserve Sharing Group's Most Severe Single Contingency and any adjustments necessary to address the Most Severe Single Contingency within a Reserve Sharing Zone.

The fourth step checks to make sure the aggregate amount of Contingency Reserve Available within the NWPP Reserve Sharing Group is at least equal to Contingency Reserve Obligation of the NWPP Reserve Sharing Group according to the requirements of BAL-002 (both the WECC and the NERC versions). If it is not, the Reserve Sharing Computer System allocates, on a pro rata basis, the additional amount of Contingency Reserve necessary to fully comply with the Contingency Reserve requirements of BAL-002. Each Participating Balancing Authority must add this adjustment amount to its total Contingency Reserve Obligations and stand ready to deploy this adjusted Contingency Reserve Obligation (excluding amounts already deployed to respond to Qualifying Events) at all times for use as Internal Reserve and Assistance Reserve.

Section 4 of this Attachment sets out the process a Participating Balancing Authority should follow to determine its Contingency Reserve Obligation(s) when communication links between the Participating Balancing Authority and the Reserve Sharing Computer System are down, or when the Reserve Sharing Computer System is unavailable.

Set forth below are explanations and formulas for each step in the process to determine the total amount of Contingency Reserve a Participating Balancing Authority is required to carry.[2] For any Participant that has more than one Balancing Authority Area within the Northwest Power Pool, the calculations below are done separately for each of its Balancing Authority Areas.

a. <u>Step One – Calculation of Participating Balancing Authority Base Contingency Reserve Obligation</u>:

   The base Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), or "CRO_{CA}" (before the adjustments described in the remainder of Section 1 of this Attachment A), is the sum of (i) three percent of the Load (as defined below) for the Participant's Balancing Authority Area(s), plus (ii) three percent of the Generation (as defined below) for the Participant's Balancing Authority Area(s).

   $$\mathbf{CRO}_{CA} = (0.03 \times \text{Generation}) + (0.03 \times \text{Load}),$$

[2] For consistency with formulas used in the Reserve Sharing Computer System, individual Participating Balancing Authority obligations are designated by the subscript "$_{CA}$." This is because the formulas in the Reserve Sharing Computer System were established when the function roughly corresponding to a Balancing Authority was referred to as a control area.

Where,

- **CRO_{CA}** = base Contingency Reserve Obligation
- **Generation** = BAA Net Generation - Designated Dynamically Scheduled Exports + Designated Dynamically Scheduled Imports [*see* Note 1]
- **Load** = BAA Net Generation - Actual Net Interchange [*see* Notes 2 and 3]
- **BAA Net Generation** = the sum of Net Generation for all generating units (whether measured by individual units or at the plant level or both) inside the Balancing Authority Area
- **Net Generation** (whether for an individual generating unit or a generating plant) = the greater of (a) the gross metered generation minus station service load, or (b) zero
- **Actual Net Interchange (NI_A)** has the meaning given to this term in the NERC Glossary
- **Scheduled Net Interchange (NI_S)** has the meaning given to this term in the NERC Glossary
- **Designated Dynamically Scheduled Exports =** all Dynamically Scheduled exports for which the sink (receiving) Balancing Authority has agreed to carry Contingency Reserve, as reflected in the Balancing Authority Area's Scheduled Net Interchange value [*see* Note 4]
- **Designated Dynamically Scheduled Imports** for which the sink (receiving) Balancing Authority has agreed to carry Contingency Reserve, as reflected in the Balancing Authority Area's Scheduled Net Interchange value [*see* Note 4]
- **Dynamically Scheduled** corresponds to the term "Dynamic Schedule," as defined in the NERC Glossary

Note 1: All generation within the Balancing Authority Area's or the NWPP Reserve Sharing Group's metered boundaries should be included in this calculation, with the only exception being generation expressly permitted to be excluded by the terms of BAL-002-WECC-3 (or comparable standards in jurisdictions outside the United States). Generation within a Balancing Authority Area by Pseudo-Tie (as defined in the NERC Glossary) is considered within the metered boundaries of the Balancing Authority Area into which it is Pseudo-Tied and is included in its generation calculation.

Note 2: Generation within a Balancing Authority Area by Pseudo-Tie is reflected in Actual Net Interchange in the ACE equation.

Note 3: Load within a Balancing Authority Area by Pseudo-Tie is reflected in Actual Net Interchange in the ACE equation. Load within a Balancing Authority Area by Pseudo-Tie is considered within the metered boundaries of the Balancing Authority Area into which it is Pseudo-Tied and is included in its load calculation by virtue of its inclusion in the Actual Net Interchange equation.

Note 4: This term captures net generation responsibility transferred, reflecting that Dynamically Scheduled generation exports can be subtracted from the exporting Balancing Authority's generation obligation (except when the source Balancing Authority and sink Balancing Authority have agreed otherwise), and Dynamically Scheduled generation imports should be added to the importing Balancing Authority's generation obligation (except when the source Balancing Authority and sink Balancing Authority have agreed otherwise).

b. Step Two – Check for Deficiency Related to Most Severe Single Contingency for the NWPP:

Once the Participating Balancing Authorities' base Contingency Reserve Obligations have been calculated, the second step in the process is to check for any potential deficiency, should the Most Severe Single Contingency for the NWPP exceed the sum of the Participating Balancing Authorities' Contingency Reserve Obligations as calculated in step one.

The NWPP's Most Severe Single Contingency is compared to the sum of all Participating Balancing Authorities' base Contingency Reserve Obligations. If the Most Severe Single Contingency is greater, the difference between these two figures (the "shortfall") is allocated among the Participating Balancing Authorities in proportion to their relative shares of the NWPP Reserve Sharing Group's base Contingency Reserve Obligation, as calculated in step one. This results in an upward adjustment to the base Contingency Reserve Obligation for each Participant's Balancing Authority Area(s).

The formulas for this step are as follows:

If $S\ CRO_{CA} < MSSC_{NWPP}$, then

$$CRO\_SHORT_{NWPP} = MSSC_{NWPP} - S\ CRO_{CA}$$

and

$$AdjCRO\_MSSC_{CA} = CRO\_SHORT_{NWPP} * CRO_{CA} / S\ CRO_{CA}$$

Where,

$S\ CRO_{CA}$ = sum of all Participating Balancing Authorities' base Contingency Reserve Obligations, as calculated through step one;

$MSSC_{NWPP}$ = the Most Severe Single Contingency for the NWPP Reserve Sharing Group, determined in accordance with the Typical Planning MSSC in real time table set forth in Attachment K;

CRO_SHORT_{NWPP} = the amount by which the Most Severe Single Contingency for the NWPP exceeds the sum of the Participating Balancing Authorities' base Contingency Reserve Obligations;

CRO_{CA} = the Participating Balancing Authority's base Contingency Reserve Obligation as calculated in step one;

$AdjCRO\_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group.

$MSSC_{NWPP}$ is revised whenever the output of the generator (or loading of the transmission line) that sets the $MSSC_{NWPP}$ increases or decreases by one MW or more.

c. <u>Step Three – Check for Deficiency Related to Most Severe Single Contingency for a Reserve Sharing Zone and Sum of Adjustments</u>:

The third step in the process is to check for any potential deficiency within a Reserve Sharing Zone if the Zone's Most Severe Single Contingency exceeds the sum of (i) the Contingency Reserve Obligation for the Zone's Participating Balancing Authorities and (ii) the amount of Contingency Reserve that can be imported from adjacent Reserve Sharing Zones. This Zone adjustment is then summed with the adjustment from step two and added to the Participant's base Contingency Reserve Obligation to give Total Contingency Reserve Obligation.

The Reserve Sharing Computer System continuously monitors transfer limits ($LIMIT_{Pathnn}$), actual flows ($ACTUAL_{Pathnn}$), and, where applicable, scheduled flows ($SCHED_{Pathnn}$) on transmission facilities connecting Reserve Sharing Zones.

If, after accounting for Contingency Reserve Obligation that can be delivered from adjacent Reserve Sharing Zones, the combined Contingency Reserve Obligations within the Zone is less than the Zone's Most Severe Single Contingency, this shortfall is allocated among the Zone's Participating Balancing Authorities in proportion to their relative shares of the aggregate Contingency Reserve Obligations (as calculated through steps one and two) for the Reserve Sharing Zone.

The formulas for adjusting Contingency Reserve Obligations, if necessary, for the Most Severe Single Contingency for a Reserve Sharing Zone are as follows:

If $S\ (CRO_{CA} + AdjCRO\_MSSC_{CA}) + ASDEL_{ZONE} < MSSC_{ZONE}$, then

$$CRO\_SHORT_{ZONE} = MSSC_{ZONE} - (S\ (CRO_{CA} + AdjCRO\_MSSC_{CA}) + ASDEL_{ZONE})$$

and

$$AdjCRO\_ZONE\_MSSC_{CA} = CRO\_SHORT_{ZONE} * (CRO_{CA} + AdjCRO\_MSSC_{CA}) / S\ (CRO_{CA} + AdjCRO\_MSSC_{CA})$$

and

$$AdjCRO_{CA} = AdjCRO\_MSSC_{CA} + AdjCRO\_ZONE\_MSSC_{CA}$$

and

$$TotCRO_{CA} = CRO_{CA} + AdjCRO_{CA}$$

Where,

$S\ CRO\_MSSC_{CA}$ = the sum of Contingency Reserve Obligations for all Participating Balancing Authorities in the Reserve Sharing Zone (as calculated through steps one and two);

CRO_MSSC_{CA} = the Contingency Reserve Obligation for a Participating Balancing Authority in the Reserve Sharing Zone, as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group;

$ASDEL_{ZONE}$ = the amount of Assistance Reserve that can be delivered to the Reserve Sharing Zone from adjacent Reserve Sharing Zones, after accounting for relevant transfer limits, actual flows, and if applicable, scheduled flows on transmission facilities connecting Reserve Sharing Zones;

$MSSC_{ZONE}$ = the Most Severe Single Contingency for the Reserve Sharing Zone;

CRO_SHORT_{ZONE} = the amount by which the Most Severe Single Contingency for the Reserve Sharing Zone exceeds the sum of (i) the aggregate Contingency Reserve Available of the Participating Balancing Authorities in the Reserve Sharing Zone (S CRO_MSSC_{ZONE}), plus (ii) amount of Assistance Reserve that can be delivered to the Reserve Sharing Zone from adjacent Reserve Sharing Zones ($ASDEL_{Lim}$);

CRO_{CA} = the Participating Balancing Authority's Contingency Reserve Obligation;

$AdjCRO\_ZONE\_MSSC_{CA}$ = the additional amount of Contingency Reserve a Participating Balancing Authority needs to carry to reflect the Most Severe Single Contingency for the Reserve Sharing Zone;

$AdjCRO\_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group;

$AdjCRO_{CA}$ = the total adjustment amounts to be added to a Participant's base Contingency Reserve Obligation to reflect any applicable adjustments for the NWPP Reserve Sharing Group's Most Severe Single Contingency and the Most Severe Single Contingency for a Reserve Sharing Zone; and

$TotCRO_{CA}$ = the Participating Balancing Authority's Contingency Reserve Obligation as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group and for its Reserve Sharing Zone.

$MSSC_{ZONE}$ is revised whenever the output of the generator (or loading of the transmission line) that sets the $MSSC_{ZONE}$ increases or decreases by one MW or more.

d. Step Four – Calculation of Aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and Check for NWPP Reserve Sharing Group Shortfall:

The fourth step in the process calculates the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and makes sure the total Contingency Reserve Available within the NWPP Reserve Sharing Group is at least equal to the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group.

The aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group is calculated by summing the total Contingency Reserve Obligations (as calculated in steps one through three) for all Participants' Balancing Authority Areas.

The formula for this step is as follows:

$$TotCRO_{NWPP} = S\ TotCRO_{CA}$$

Where,

$TotCRO_{NWPP}$ = the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group; and

$S\ TotCRO_{CA}$ = the sum of the total Contingency Reserve Obligations of all Participating Balancing Authorities, as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group and for applicable Reserve Sharing Zones.

If the Contingency Reserve Available within the NWPP Reserve Sharing Group is less than the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group, the difference between these two figures (the "shortfall") is allocated among the Participating Balancing Authorities in proportion to their relative shares of the NWPP Reserve Sharing Group's Contingency Reserve Obligation (without factoring in adjustments for shortfalls within a Reserve

Sharing Zone). This results in an upward adjustment to the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s).

The formulas for this final check are as follows:

If $TotAvailCR_{NWPP} < TotCRO_{NWPP}$, then

$TotCRO\_SHORT_{NWPP} = TotCRO_{NWPP} - TotAvailCR_{NWPP}$

and

$AdjCRO\_SHORT_{CA} = (TotCRO\_SHORT_{NWPP} * (CRO_{CA} + AdjCRO\_MSSC_{CA}) / S (CRO_{CA} + AdjCRO\_MSSC_{CA}))$

Where,

$TotCRO_{NWPP}$ = the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group;

$TotAvailCR_{NWPP}$ = the total amount of Contingency Reserve Available in the NWPP Reserve Sharing Group;

$TotCRO\_SHORT_{NWPP}$ = the amount by which the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group exceeds the total Contingency Reserve Available;

CRO_{CA} = the Participating Balancing Authority's base Contingency Reserve Obligation as calculated in steps one;

$AdjCRO\_SHORT_{CA}$ = the adjustment to the Participating Balancing Authority's Contingency Reserve Obligation to reflect the shortfall in total Contingency Reserve Available; and

$AdjCRO\_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group.

Each Participant must add the adjustment amount ($AdjCRO\_SHORT_{CA}$) to the total Contingency Reserve Obligation for its Balancing Authority Area(s) as calculated in step three ($TotCRO_{CA}$) and stand ready to deploy the combined amount of Contingency Reserve Available (excluding amounts already deployed to respond to a Qualifying Event) at all times for use as Internal Reserve and Assistance Reserve.

The NWPP Reserve Sharing Group will experience a shortfall only if one or more Participants have not fully met their Contingency Reserve Obligations.

2. Permitted Amounts and Types of WECC Operating Reserve - Supplemental

A Participating Balancing Authority's Contingency Reserve Obligation(s) may be met with WECC Operating Reserve - Supplemental, provided that any WECC Operating Reserve - Supplemental applied to a Participating Balancing Authority's Contingency Reserve Obligation can be made fully effective within 10 minutes.

Permitted Sources of WECC Operating Reserve - Supplemental

A Participating Balancing Authority is permitted to use WECC Operating Reserve - Supplemental to meet a portion of its Contingency Reserve Obligation(s) calculated in accordance with Section 1 of this Attachment A, the following may be used as sources of WECC Operating Reserve - Supplemental:

1. WECC Operating Reserve - Spinning,
2. WECC Operating Reserve - Supplemental,
3. Interchange Transactions designated by the Source Balancing Authority as WECC Operating Reserve - Supplemental,
4. Reserve held by other entities by agreement that is deliverable on Firm Transmission Service,
5. A resource, other than generation or load, that can provide energy or reduce energy consumption,
6. Load, including demand response resources, demand-side management resources, direct control load management, interruptible load or interruptible demand, or any other load made available for curtailment by the Participating Balancing Authority or the NWPP Reserve Sharing Group via contract or agreement, and

7. All other load, not identified in the foregoing items, once a Reliability Coordinator for the Northwest Power Pool has declared an energy emergency alert signifying that interruption of Firm Demand is imminent or in progress.

3. Participating Balancing Authority Calculation of Contingency Reserve Obligation(s) When Communications with Reserve Sharing Computer System Are Disrupted

During periods when communication links between a Participating Balancing Authority and the Reserve Sharing Computer System are down, or when the Reserve Sharing Computer System is unavailable, responsibility for calculating Contingency Reserve Obligations shifts to the Participating Balancing Authority. Any Participating Balancing Authority that is unable to access the Reserve Sharing Computer System's calculation of its Contingency Reserve Obligations should use good-faith estimates of the inputs needed to determine its Contingency Reserve Obligation, based on the last available input data known to be valid, and apply as many of the steps described in Section 1 of this Attachment A as it can, consistent with good utility practice. The Participating Balancing Authority should continue this process, adjusting as appropriate for relevant changes to system conditions, until availability of and communications with the Reserve Sharing Computer System are restored.

Attachment B

Qualifying Events

A "Qualifying Event" is any single event described in subsections (A), (B), (C), or (D) below, or any series of such otherwise single events, with each separated from the next by one minute or less. Any capitalized term used below that is not defined within this document has the meaning given to it in the NERC Glossary. This Attachment B may be modified from time to time by action of the RSG Committee.

(A) Sudden Loss of Generation

a. due to
    i. unit tripping (*see note 1 below), or*
    ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
    iii. sudden unplanned outage of transmission Facility;
b. and, that causes an unexpected change to the responsible entity's ACE (*see note 2 below*)

(B) Sudden Loss of an Import

a. due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. (*See note 3 below*).

(C) Sudden Restoration of Demand

a. that was used as a resource that causes an unexpected change to the responsible entity's ACE

(D) Energy Emergency Alert

a. where a Participating Balancing Authority's inability to meet Firm Demand such that the Participating Balancing Authority has requested its Reliability Coordinator to declare, and the Reliability Coordinator has declared an Energy Emergency Alert 3 (as described in NERC Standard EOP-011 or a successor standard) the Participant:
    i. May utilize its CRO to serve Firm Demand while the Participant is in an EEA 3;

ii. Must keep the RSG Computer System current with any portion of its Contingency Reserve Available already in use (UsedCR_{CA});

iii. Should reach out to neighboring BA's to verify no energy is available;

iv. Should reach out to cut-plane monitors for limit verification of any cut-planes with constraints impacting the BA's ability to receive Assistance Reserves;

v. May request Assistance Reserve through the NWPP Reserve Sharing Program for up to 60 minutes to prevent shedding Firm Demand, not to restore their Contingency Reserves.

1. Once the timeframe above has been depleted, then the Participant may continue to utilize its CRO to server Firm Demand. The Participant may need to shed Firm Demand to maintain Reporting ACE until the Participant is no longer in an EEA 3.

Note 1:

For purposes of this Attachment B, the term "unit tripping" means:

(1) the automatic operation of a device or capability designed to protect a power-producing resource from damage, or

(2) the unexpected failure of a power-producing resource to maintain, increase, or remain available due to equipment failure, or

(3) the unexpected failure of a power-producing resource to start (a) due to equipment failure, and (b) not associated with the failure to procure fuel,

which, in all cases, results in loss of MW output serving (or needed to serve) one or more Participants' Demand obligations.

Note 2:

The events described in Note 1 are Qualifying Events even when they do not result in an immediate change to the responsible entity's ACE.

Note 3:

Given typical operating practices followed in the Western Interconnection, the loss of an import would generally be expected to result in a corresponding adjustment to generation.

Attachment C

Reserve Sharing Zones and Assistance Reserve Responder Levels

Each Reserve Sharing Zone, as identified in the table below, has one or more Balancing Authority Participants.

Zones	Balancing Authority Participants
Alberta (AB)	AESO
Arizona -Nevada (AZNV)	AZPS, BNBA, DEAA, GRID, SRP, TEPC, WALC & NEVP
British Columbia (BC)	BCHA
Eastern Colorado (ECO)	PSCO
Mountain West (MTWEST)	IPCO & PACE
Northern California (NCAL)	BANC & TID
Pacific Northwest – Montana (PNWMT)	AVA, AVRN, BPA, CHPD, DOPD, GCPD, GRID, GWA, NWMT, PACW, PGE, PSEI, SCL, TPWR, & WAUW
Southern California (SCAL)	IID
Texas – New Mexico (TXNM)	EPE & PNM
Western Colorado (WCO)	WACM



Assistance Reserve Responder Levels

Each Reserve Sharing Zone has multiple levels for providing Assistance Reserve. Level 1 is the list of initial providers. If there is insufficient Assistance Reserve at Level 1 or there are transmission constraints between Reserve Sharing Zones, additional zones will be included by moving out one level at a time until there is sufficient Assistance Reserve or all Participating Balancing Authorities are included.

		Responding Zone									
		AB	AZNV	BC	ECO	MTWEST	NCAL	PNWMT	SCAL	TXNM	WCO
Requesting Zone	AB	-	4	1	6	3	3	2	5	5	5
	AZNV	5	1	4	3	2	4	3	1	1	2
	BC	1	3	-	5	2	2	1	4	4	4
	ECO	6	2	5	-	3	5	4	3	3	1
	MTWEST	3	2	2	4	1	2	1	3	3	3
	NCAL	4	4	3	6	2	1	2	5	5	5
	PNWMT	3	3	2	5	2	2	1	4	4	4
	SCAL	5	1	4	3	2	4	3	-	1	2
	TXNM	5	1	4	3	2	4	3	1	1	2
	WCO	6	2	5	1	3	5	4	3	3	-

Alberta Zone (AB)

Level 1: BC
Level 2: BC + PNWMT
Level 3: BC + PNWMT + MTWEST + NCAL
Level 4: BC + PNWMT + MTWEST + NCAL + AZNV
Level 5: BC + PNWMT + MTWEST + NCAL + AZNV+ SCAL + TXNM + WCO
Level 6: BC + PNWMT + MTWEST + NCAL + AZNV+ SCAL + TXNM + WCO + ECO

Arizona Nevada Zone (AZNV)

Level 1: AZNV + SCAL + TXNM
Level 2: AZNV + SCAL + TXNM + MTWEST + WCO
Level 3: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

British Columbia Zone (BC)

Level 1: AB + PNWMT
Level 2: AB + PNWMT + MTWEST + NCAL
Level 3: AB + PNWMT + MTWEST + NCAL + AZNV

Level 4: AB + PNWMT + MTWEST + NCAL + AZNV + SCAL + TXNM + WCO
Level 5: AB + PNWMT + MTWEST + NCAL + AZNV + SCAL + TXNM + WCO + ECO

Eastern Colorado Zone (ECO)
Level 1: WCO
Level 2: WCO + AZNV
Level 3: WCO + AZNV + MTWEST + SCAL + TXNM
Level 4: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT
Level 5: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC
Level 6: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + AB

Mountain West Zone (MTWEST)
Level 1: MTWEST + PNWMT
Level 2: MTWEST + PNWMT + AZNV + BC + NCAL
Level 3: MTWEST + PNWMT + AZNV + BC + NCAL + AB + SCAL + TXNM + WCO
Level 4: MTWEST + PNWMT + AZNV + BC + NCAL + AB + SCAL + TXNM + WCO + ECO

Northern California Zone (NCAL)

Level 1: NCAL
Level 2: NCAL + MTWEST + PNWMT
Level 3: NCAL + MTWEST + PNWMT + BC
Level 4: NCAL + MTWEST + PNWMT + BC + AB + AZNV
Level 5: NCAL + MTWEST + PNWMT + BC + AB + AZNV + SCAL + TXNM + WCO
Level 6: NCAL + MTWEST + PNWMT + BC + AB + AZNV + SCAL + TXNM + WCO + ECO

Pacific Northwest-Montana Zone (PNWMT)

Level 1: PNWMT
Level 2: PNWMT + BC + MTWEST+ NCAL
Level 3: PNWMT + BC + MTWEST+ NCAL + AB + AZNV
Level 4: PNWMT + BC + MTWEST+ NCAL + AB + AZNV + SCAL + TXNM + WCO
Level 5: PNWMT + BC + MTWEST+ NCAL + AB + AZNV + SCAL + TXNM + WCO + ECO

Southern California Zone (SAL)

Level 1: AZNV + TXNM
Level 2: AZNV + TXNM+ MTWEST + WCO
Level 3: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

Texas New Mexico Zone (TXNM)

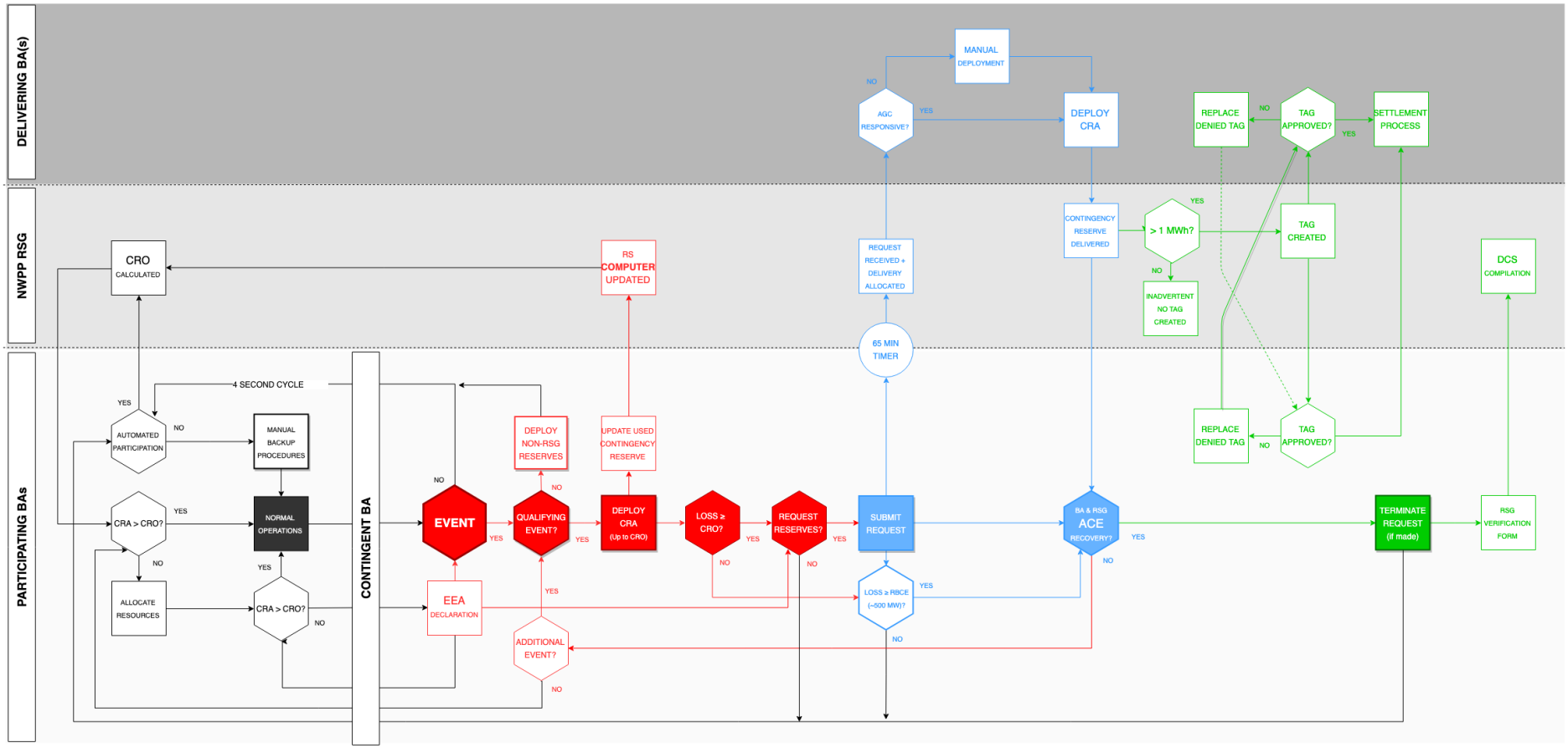
Level 1: AZNV + SCAL + TXNM
Level 2: AZNV + SCAL + TXNM + MTWEST + WCO
Level 3: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

Western Colorado Zone (WCO)

Level 1: ECO
Level 2: ECO + AZNV
Level 3: ECO + AZNV + MTWEST + SCAL + TXNM
Level 4: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT
Level 5: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + NCAL
Level 6: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + NCAL + AB

Attachment D

NWPP Process Charts



NORMAL OPERATIONS → DISTURBANCE → REQUEST → RESOLUTION

CONTINGENCY RESERVE OBLIGATION (CRO)

- Zonal MSSC
- 3% GENERATION + 3% LOAD

QUALIFYING EVENTS

- Sudden Loss of Generation
- Sudden Loss of an Import
- Sudden Restoration of a Demand
- Energy Emergency Alert

Four Minute Requirement

- 4 min allows adequate response time for ACE
- < 4 mins - RSG responsible
- > 4 mins - BA responsible if compliance failure occurs

RESERVE REQUESTS

- Request is optional
- **RBCE = Reportable Balancing Contingency Event**

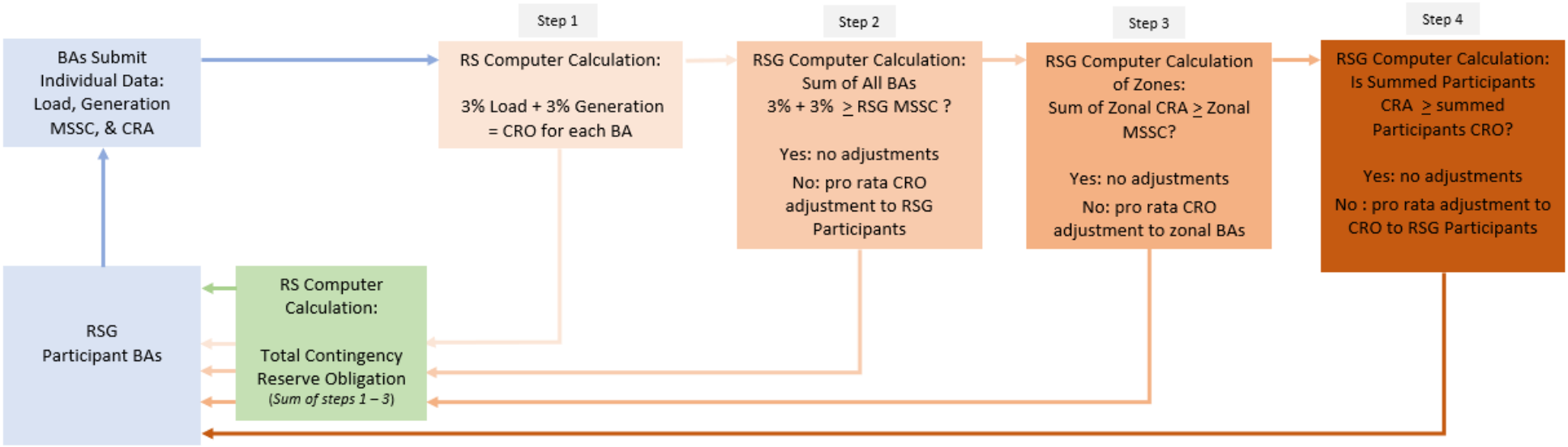
SETTLEMENT

- Powerdex Mid-Columbia Hourly Index

Northwest Power Pool
RESERVE SHARING PROGRAM
PROCESS CHART v19

NORTHWEST PowerPool

Attachment A – Calculation of CRO

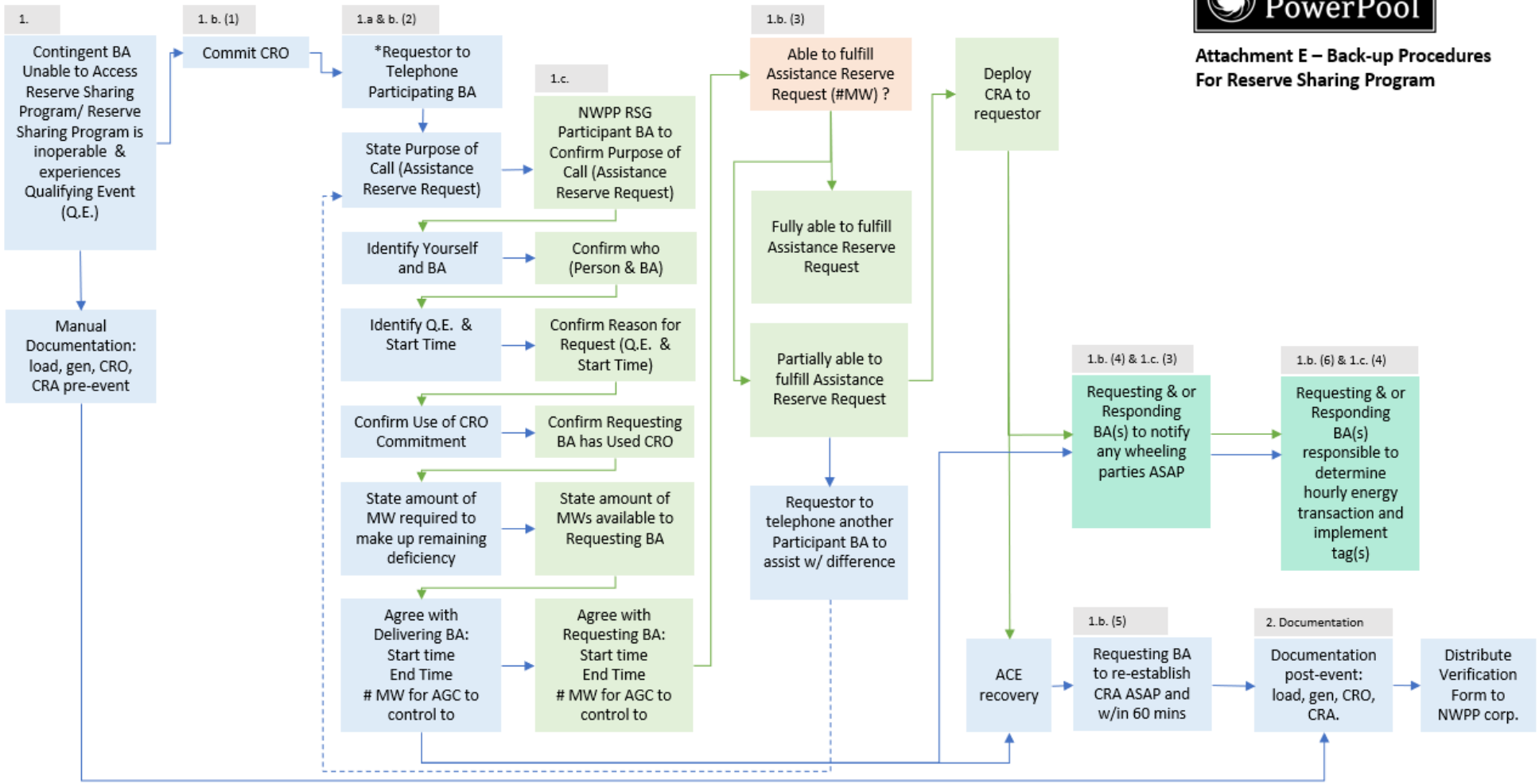


ICCP outputs for each step:
Step 1: BA-CRO
Step 2: BA-ADJ_MSSC_POOL
Step 3: BA-ADJ_MSSC_ZONE
Step 4: BA-ADJCRO_POOL

Total Contingency Reserve Obligation ICCP output: BA-TOTCRO

NORTHWEST PowerPool

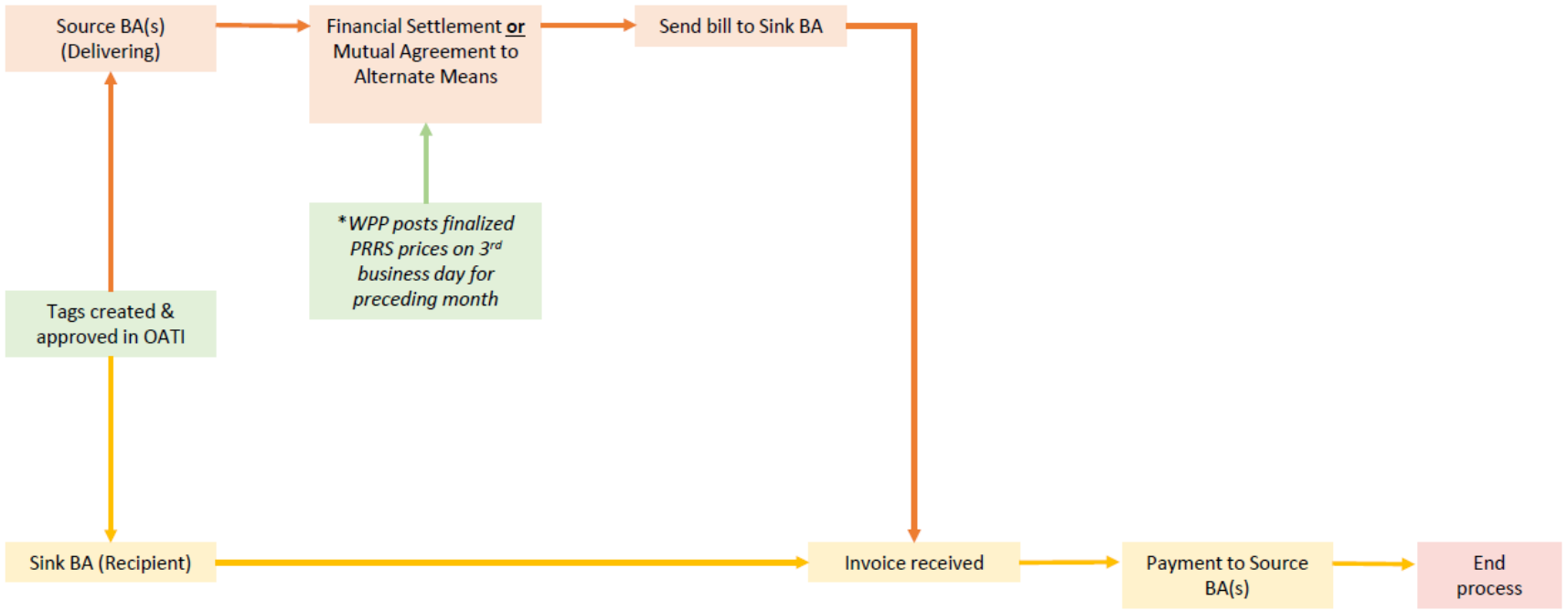
Attachment E – Back-up Procedures For Reserve Sharing Program



* To minimize potential transmission problems call adjacent BA first. If adjacent BA is unable to fulfill Assistance Reserve Request, contingent BA should move and call next adjacent BA. The process would be the same if the adjacent BA is able to partially fill request or unable to fill request.

NORTHWEST PowerPool

Section K – Settlement Process



Attachment E

BACKUP PROCEDURES FOR RESERVE SHARING PROGRAM

1. Participant Cannot Access Reserve Sharing Computer System or Reserve Sharing Computer System Is Inoperable

Reserve Sharing Requests and delivery of Assistance Reserve are normally implemented through the Reserve Sharing Computer System. When the Reserve Sharing Computer System is inoperable or inaccessible, a Participant that needs to make a Reserve Sharing Request should contact other Participants by telephone to request Assistance Reserve. Attachment D reflects the respective process described in this attachment. The provisions below (Sections 1.a, 1.b, and 1.c) will apply for the manual backup procedure. The settlement process for delivery of Assistance Reserve using the backup procedure is the same as for the automated reserve sharing process, except that requesting and responding Participants must agree (on a case-by-case basis) to any reserve sharing transactions instead of obtaining the information from the Reserve Sharing Computer System. This process must be in accordance with Attachment G for production of after-the-fact tags and in accordance with existing reliability standards and regional business practices.

a. Transmission Limitations; Adjacent Utilities

To minimize potential transmission problems, whenever possible a Participant that needs to request Assistance Reserve by telephone should contact an adjacent Participant first.

b. Backup Reserve Sharing Procedure – Telephone Requests

Because NERC BAL-002-3 requires recovery of Reporting ACE within 15 minutes, the number of telephoned assistance requests that a Participant's dispatcher can make is limited. To enhance Participants' ability to meet this standard, Participants may use the following procedure (and Participants may use any economic arrangements under existing contracts by mutual agreement at any point in the following sequence):

(1) As provided in Section E.2, a Participant must commit its Internal Reserve up to the full amount of its Contingency Reserve Obligation before requesting Assistance Reserve.

(2) If a Participant that has deployed its Contingency Reserve Obligation and needs additional capacity to meet the 15-minute criterion, that Participant may call another Participant for assistance. The responding Participant will make available its unused Contingency Reserve Available up to its Contingency Reserve Obligation.

The caller must:

(a) state that the purpose of the call is to make a Reserve Sharing Request,

(b) identify who is making the request,

(c) identify the Qualifying Event it has experienced and the start time of the event,

(d) confirm that it committed to use Contingency Reserve up to the full amount of its Contingency Reserve Obligation to respond to the event,

(e) state the amount of Assistance Reserve that is required to make up the remaining deficiency, and

(f) agree with the responding Participant on the amount, start-time, and end-time of the Contingency Reserve delivery to be entered into the AGC controller total. The end-time may be shortened thereafter, if the requesting Participant determines that it does not need Assistance Reserve through the original end-time.

(3) If the Assistance Reserve made available and delivered from the responding Participant is insufficient to cover the Qualifying Event, the requesting Participant will cover the remaining deficit by requesting Assistance Reserve from another Participant.

(4) As soon as possible, the requesting Participant must notify any intermediate wheeling Balancing Authority(s) of the scheduled delivery of Assistance Reserve and its duration. Each Participating Balancing Authority that is needed for intermediate wheeling will make transmission capacity available up to its maximum operating limit by any means necessary including the curtailment of interruptible schedules.

(5) The Participant requesting assistance must re-establish its Contingency Reserve Available that is ready for deployment (to at least the level of its Contingency Reserve Obligation) as soon as possible by adding generation, adjusting interchange schedules, or dropping load. As provided in Section F.3, a Participant that requests Assistance Reserve must relinquish the Assistance Reserve within 60 minutes following the start of the Qualifying Event.

(6) Any Participant that requests Assistance Reserve must contact the party within its organization that is responsible for energy scheduling and notify that party of the actions taken to request Assistance Reserve. The party responsible for scheduling must then contact its counterpart from the responding Participant to determine an agreed-upon hourly energy transaction and to agree on transaction wheeling amounts in accordance with the paths identified in the Participants pre-defined tag templates.

c. Backup Reserve Sharing Procedure – Telephone Responses

The following responses may be appropriate for a Participant that receives a Reserve Sharing Request by telephone:

(1) If a Participant that has deployed its Contingency Reserve needs additional capacity to meet the 15-minute criterion, that Participant may call another Participant for assistance.

The responding Participant will make available its unused Contingency Reserve up to its Contingency Reserve Obligation.

(2) The Participant that is being asked to provide Assistance Reserve may make the following responses:

(a) confirm that the purpose of the call is to make a Reserve Sharing Request,

(b) confirm who is making the request,

(c) confirm the reason for the request (*e.g.*, identify the Qualifying Event and the start time of the event),

(d) confirm that the requesting Participant has committed to use Contingency Reserve Available up to the full amount of its Contingency Reserve Obligation to respond to the event,

(e) state the amount of Assistance Reserve available to the requesting Participant,

(f) agree with the requesting Participant on the amount, start-time, and end-time of the Assistance Reserve to be entered into the AGC controller total.

(3) As soon as possible, the responding Participant should notify any intermediate wheeling Balancing Authority(s) of the scheduled delivery of Assistance Reserve energy and its duration. Each Participating Balancing Authority that is needed for intermediate wheeling will make transmission capacity available up to its maximum operating limit by any means necessary including the curtailment of interruptible schedules.

(4) Any Participant that provides Assistance Reserve must contact the party within its organization that is responsible for energy scheduling and notify that party of the actions taken to provide Assistance Reserve. The party responsible for scheduling must then contact its counterpart from the requesting Participant to determine an agreed-upon hourly energy transaction.

2. Documentation

Any Participant that requests Assistance Reserve using the backup procedures in this Attachment E must document its load, generation, Contingency Reserve Obligation, and Contingency Reserve Available immediately before the Qualifying Event. It must document the amount of its capacity lost or other characteristics of the Qualifying Event, the amount and components of Contingency Reserve deployed, and the amount of Assistance Reserve requested and received. The requesting Participant must also comply with Attachment G, Backup Process for After-the Fact Reserve Sharing Tags.

NWPP RSG Verification Forms are available on the WPP Website. The requesting Participant must send this documentation to all responding Participants, and to the WPP Staff, on the next working day.

Attachment F

TRANSMISSION MAPPING AND TAG TEMPLATE CHANGE PROCESS

A. Process for Changing Tagging Templates Delivery Paths Between NWPP Reserve Sharing Participants

1. Any Participant that wishes to request a change to the transmission mapping set forth in Participants' pre-defined tag templates must first obtain the agreement of all other Participants that would be affected by the requested change.
2. All affected Participants must be given adequate time to make any software changes to downstream or legacy scheduling systems.
3. Participant(s) requesting the change must complete any necessary registrations (or updates to registrations) related to the NAESB Electric Industry Registry (EIR) and Western Interchange Tool (WIT) Registry, or any successor industry registration systems.
4. Participants must submit requests for changes to the tag templates to the WPP Staff.
5. OATI will coordinate testing of the new or revised tag templates and confirm that the templates will pass WIT Registry validations.
6. WPP Staff and the affected Participants will coordinate with OATI to determine an implementation date and time for the new templates.
7. WPP Staff will advise all Participants of the implementation date for the revised templates.
8. OATI will make appropriate tag template changes effective as of the implementation date and time.

B. Process for Changing Tag Templates with No Change to Delivery Paths

(No Impact to Other Balancing Authorities)

1. The Participant with changes will notify the WPP Staff and provide WPP Staff with required changes to its tag templates.
2. The Participant with changes will complete any necessary EIR and WIT registrations or updates.
3. WPP Staff will communicate the requested changes to OATI.
4. OATI will coordinate testing of new or revised tag templates and confirm that the templates will pass WIT validations.

5. WPP Staff and the requesting Participant will determine an implementation date and time for the new tag templates.
6. OATI will make appropriate tag template changes effective as of the implementation date and time.
7. OATI will provide the WPP with the most current workbook of NWPP tag templates.

C. Process for Adding a New Participant to NWPP Reserve Sharing Program

1. WPP Staff will provide a newly admitted Participant(s) with the tag templates for further development to reflect the inclusion of the new Participant(s). If a new Reserve Sharing Zone is required, Attachment C will be revised to reflect the addition of a new Reserve Sharing Zone.
2. The New Participant(s) will provide WPP Staff with a workbook containing only their newly developed tag matrix (to and from each Participant BA) of completed tag templates.
3. WPP Staff will assist with distribution of these new tag templates to all Participants for review as required.
4. Participant(s) must review the new templates and implement any necessary changes to their own accounting and billing systems.
5. WPP Staff will communicate approved new tag templates to OATI.
6. OATI will coordinate testing of the new tag templates and confirm that the templates will pass WIT validations.
7. WPP Staff and all Participants will determine an implementation date and time for the new templates.
8. WPP Staff will advise all Participants of the implementation date and time for the new templates.
9. OATI will make the new tag templates effective as of the implementation date and time.

Attachment G

Backup Process for After-The-Fact Reserve Sharing Tags

A. Failure of Participant Internal Program or Reserve Sharing Computer System

If a Participant that has requested Assistance Reserve (or is providing Assistance Reserve) experiences a failure of any internal program related to reserve sharing, or if a Reserve Sharing Request is made or in effect during a time when the Reserve Sharing Computer System is not functioning, then the Participants receiving and providing Assistance Reserve energy will be responsible for all necessary after-the-fact tagging.

B. Failure of Automated After-the-Fact Tagging Process

If the automated tag creation process fails,

1. WPP Staff will
    a. contact OATI and coordinate the next possible time OATI can rerun automated tag creation for the event;
    b. make reasonable efforts (and request that OATI make reasonable efforts) to give Participants at least 24 hours' advance notice before the reissuing of the tags, and if this is not possible, attempt to give notice as far in advance as feasible; and
    c. notify Participants by e-mail distribution of the re-issuance of the tags.
2. If the affected Participants anticipate that the automated tag creation process will not be able to reissue the tags before the after-the-fact tagging deadline, the sink Participant will coordinate with the source Participants to facilitate the sink Participant's efforts to manually issue after-the-fact tags according to the most recent reserve sharing tag templates.
3. Participants shall contact WPP Staff to resolve failure of the automated tag creation process during normal business hours.

C. Replacing Denied Reserve Sharing Tags

1. If one Participant denies an after-the-fact the tag (properly or not), the denying Participant will coordinate with all other Participants to facilitate the denying Participant's efforts to manually reissue the after-the-fact tag(s).

a. If the problem with the original tag was due to an error in the tag template, the denying Participant will immediately notify all other Participants listed in the template of the necessary correction.

b. Participants needing to correct a tag template will follow the appropriate procedures specified in Attachment F to make changes to the tag template.

2. If more than one Participant denies a tag, the sink Participant will coordinate with all other affected Participants to facilitate the sink Participant's efforts to manually reissue the after-the-fact tag.

c. If the problem with the original tag was due to an error in the tag template, the denying Participants will immediately notify all other Participants listed in the template of the necessary correction.

d. Participants needing to correct a tag template will follow the appropriate procedures specified in Attachment F to make changes to the tag template.

Attachment H

Balancing Authority Areas of the
Participating Balancing Authorities

Alberta Electric System Operator (AESO)

Arizona Public Service Company (AZPS)

Arlington Valley, LLC (DEAA)

Avangrid Renewables, LLC (AVRN)

Avista Corporation (AVA)

Balancing Authority of Northern California (BANC)

British Columbia Hydro and Power Authority (BCHA)

Bonneville Power Administration (BPAT)

Chelan County Public Utility District (CHPD)

Douglas County Public Utility District (DOPD)

El Paso Electric Company (EPE)

First LightEnergy, LLC (BNBA)

Grant County Public Utility District (GCPD)

Gridforce Energy Management, LLC (GRID)

Idaho Power Company (IPCO)

Imperial Irrigation District (IID)

BHEM Power Watch, LLC (GWA)

Nevada Power (NEVP)

NorthWestern (NWMT)

PacifiCorp East (PACE)

PacifiCorp West (PACW)

Portland General Electric (PGE)

Public Service Company of Colorado (PSCo)

Public Service Company of New Mexico (PNM)

Puget Sound Energy (PSE)

Salt River Project Agriculture Improvement and Power District (SRP)

Seattle City Light (SCL)

Tacoma Power (TPWR)

Tucson Electric Power Company (TEPC)

Turlock Irrigation District (TID)

Western Area Power Administration – Desert Southwest Region (WALC)

Western Area Power Administration – Rocky Mountain Region (WACM)

Western Area Power Administration Upper Great Plains West (WAUW)

Attachment I

Reserved for Future Use

Attachment J

Reserved for Future Use

Attachment K

NWPP Reserve Sharing Group
MSSC and Long-Term Zonal MSSC Limit, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multi Use Transformer(s) Tables

1. Balancing Authority Area MSSC, NWPP Reserve Sharing Group Long-Term Zonal MSSC Limit, and NWPP Reserve Sharing Group Long-Term MSSC Limit.

The Participant Balancing Authorities have documented their BAA MSSCs in the table below which are used to derive the Long-Term Zonal MSSC Limit and the NWPP Reserve Sharing Group Long Term MSSC limit under normal system conditions.

Zone	Resource(s)	Reporting/ Operating BAA	Maximum Allowable Zonal MSSC MW	BAA System Normal MSSC MW	Plant Capability	Modeled Outage
Alberta	Genesse #3	AESO	466	466	1286	Loss of generation
Arizona - Nevada	Arlington Generation	AZPS	1122	565	600	Loss of transmission Line
	Arlington Valley	DEAA		580	600	Loss of transmission Line
	BrightNight PV Solar Project	BNBA		300	300	Loss of tie line
	Harquahala – Hassayampa Tie Line	SRP		975	1068	Loss of Transmission Line
	Gila River Blocks 2 &/ 3	TEPC		605	1100	Loss of generation
	Southpoint Energy Center	WALC		250	520	Loss of generation
	Silverhawk	NEVP		620	1055	Loss of transmission Line
British Columbia	Revelstoke – 3 Units	BCHA	1505	1505	2505	Revelstoke 500 kV main bus, three units (5MB2)
Eastern Colorado	Rush Creek Gen Tie	PSCO	1600	1600	1600	RAS Action
Southern California	El Centro Unit 3 / 230kV S-Line	IID	270	117/270	134	Loss of generation or line if scheduled greater than unit
Mountain West	Langley Gulch	IPC	1500	329	329	Unit trip of Langley Gulch – various issues
	Jim Bridger – 2 Units on RAS	PACE		1212	2120	RAS Action
Northern California	Consumnes	BANC	306	306	612	1X1 Generator outage, Gen Tie to plant
	Walnut Energy Center	TID		129	258	Loss of generation
Pacific Northwest - Montana	Noxon Plant RAS Trip	AVA	1500	540	550	Nox 239 East bus with RAS armed

	Schoolhouse	AVRN		598	598	Loss of John Day 239/500 kV transformer
	Columbia Generation Stn	BPAT		1180	1180	Loss of generation
	Rocky Reach – River Crossing 7-8-9	CHPD		410	1272	River crossing 7-8-9
	Wells	DOPD		168	840	Loss of generator step-up transformer (T1-T5) at Wells
	Wanapum – 4 Units	GCPD		440	1000	Trip of Wanapum Powerhouse #1 line or #2 line
	Centralia #2	GRID		710	710	Loss of generation
	BHE Power Watch	GWA		189	189	Loss of Hay Lakke-Rim Rock East & West 230 kV Generation Tie Line
	Clearwater	NWMT		750	1490	Loss of generation or generator lead line
	Chehalis	PACW		540	540	Loss of Napavine-Chehalis 500 kV line
	Carty	PGE		490	490	Loss of generation or generator lead line
	Penstemon Solar, Wild Horse Wind, Vantage Wind	PSE		382	382	230 kV Wind Ridge – Wanapum line
	Boundary Unit #55 or #56	SCL		234	1106	Loss of generation
	Mossyrock	TPWR		203	378	Generator – Transmission outage
	Fort Peck	WAUW		44	90	Loss of generation
Texas – New Mexico	Newman 5 in 2x1 configuration	EPE	900	228	268	Loss of generation
	Afton	PNM		235	235	Loss of generation
Western Colorado	Laramie River Station #2 or #3	WACM	570	570	570	Loss of generation

NWPP RSG Long-Term MSSC Limit	**Eastern Colorado Zone**		**1600**			

2. Jointly Owned Dynamic Generation Resources

This table below is a listing of jointly owned dynamic generation that could be considered a BCE under certain outage configurations.

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Four Corners 4	APS	770	1540	AZPS 70%	*
Four Corners 5		770		PNM 13%	*
				SRP 10%	*
				TEPC 7%	*
Pale Verde 1	APS	969	2907	APS	*
Pale Verde 2		969		EPE	*
Pale Verde 3		969		PNM	*
				SRP	*
Rock Island	CHPD	216	606	AVA 10%	*
				CHPD 50%	*
				PSE 40%	*
Rocky Reach – River Crossing 7-8-9	CHPD	410	1272	AVA 10%	*
				CHPD 44.46%	*
				DOPD 5.54%	*
				PSE 40%	*
Wells	DOPD	168	840	AVA	*
				CHPD	*
				DOPD	*
				PSE	`*

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Priest Rapids – 4 Units	GCPD	365	930	AVA	*
				GCPD	*
				PACW	*
				PGE	*
				PSE	*
				SCL	*
				TPWR	*
Wanapum - 4 units	GCPD	440	1000	AVA	*
				NWMT	*
				PACW	*
				PGE	*
				PSE	*
Colstrip 3 & 4	NWMT	740	1480	AVA	222
				NWMT	444
				PACW	148
				PGE	296
				PSE	370
					1480
Luna	PNM	570	570	PNM 66.33%	380
				TEPC 33.33 %	190
					570
Hermiston / Perennial	PACW	474	474	GRID	237
					237
					474

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Jim Bridger – RAS 2 Unit + Remote Wind	PACE	1212	2120	IPC	707
				PACE	1413
					2120
Gila River - *Blocks 1 & 4	SRP	550	2200	SRP 100%	1100
Gila River - *Blocks 2 & 3	TEPC	585		SRP 100%	1100
					2200
TEP and SRP have their own share based on blocks. *Under normal conditions this is not a JOU however SRP may report entire 2200MW based on N-4 conditions.*					
Springerville 1 & 2	**TEPC	450		TEP	*
Springerville 3	*PNM	458		PNM	*
				SRP	*
PNM does not own the generation, but PNM ACE is affected by the loss of generation and must request MW during disturbances to recover. **Under normal conditions this is not a JOU however TEP may report the entire amount based on potential N-4 conditions*					
Springerville 4	SRP	410		SRP	*

3. Jointly Owned Static Generation Resources

This table is a listing of jointly owned static generation that could be considered a BCE under certain outage configurations.

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Valmy	NEVP	268	395	IPC	134
				NEVP	261
					395

4. Multi Use Transformer(s)

This is a listing of transformers that are jointly utilized that could be a BCE under studied outage configurations.

Transformer(s)	Operating BA	Facility Rating	BA(s) with associated transformers	Generators	Generating Capacity in MW
John Day	BPA	1300 MVA	AVRN	Klondike I, II, III A, III GE, III Siemens, Starpoint, Hay Canyon, Golden Hills	809
			PGE	Biglow 1, Biglow 2, Biglow 3	450
					1259
Slatt	BPA	1300 MVA	AVRN	Montague Wind, Montague Solar	363
			BPA	Shepherds North (North Hurlburt)	265
			BPA	Shepherds South (South Hurlburt)	290
			BPA	Horseshoe Bend (Shepherds Central)	290
					1208
Rock Creek	BPA	1300 MVA	AVRN	Juniper Canyon, Lund Hil	299
			BPA	Windy Flats/Dooley	262
			BPA	White Creek Wind	205
			BPA	Harvest Wind	99
			PAC	Goodnoe Hills	150
					1015

Attachment L

Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

The following is a listing of the NWPP Reserve Sharing Group Participants that are monitors of the major transfer facilities and cut planes between Reserve Sharing Zones:

1) The Alberta Electric System Operator Balancing Authority (AESO) monitors the cut plane connecting the Alberta Reserve Sharing Zone with the British Columbia Reserve Sharing Zone,

2) The Bonneville Power Administration (BPA) Balancing Authority monitors the cut plane connecting the Pacific Northwest-Montana Reserve Sharing Zone with the British Columbia Reserve Sharing Zone,

3) The Idaho Power (IPC) Balancing Authority monitors the cut plane connecting the Mountain West Reserve Sharing Zone with the Pacific Northwest-Montana Reserve Sharing Zone,

4) The Balancing Authority of Northern California Balancing Authority (BANC) monitors the cut plane connecting the Pacific Northwest-Montana Reserve Sharing Zone with the Northern California Reserve Sharing Zone,

5) The PacifiCorp (PAC) Balancing Authority monitors the cut plane connecting the Mountain West Reserve Sharing Zone with the Arizona Nevada Reserve Sharing Zone,

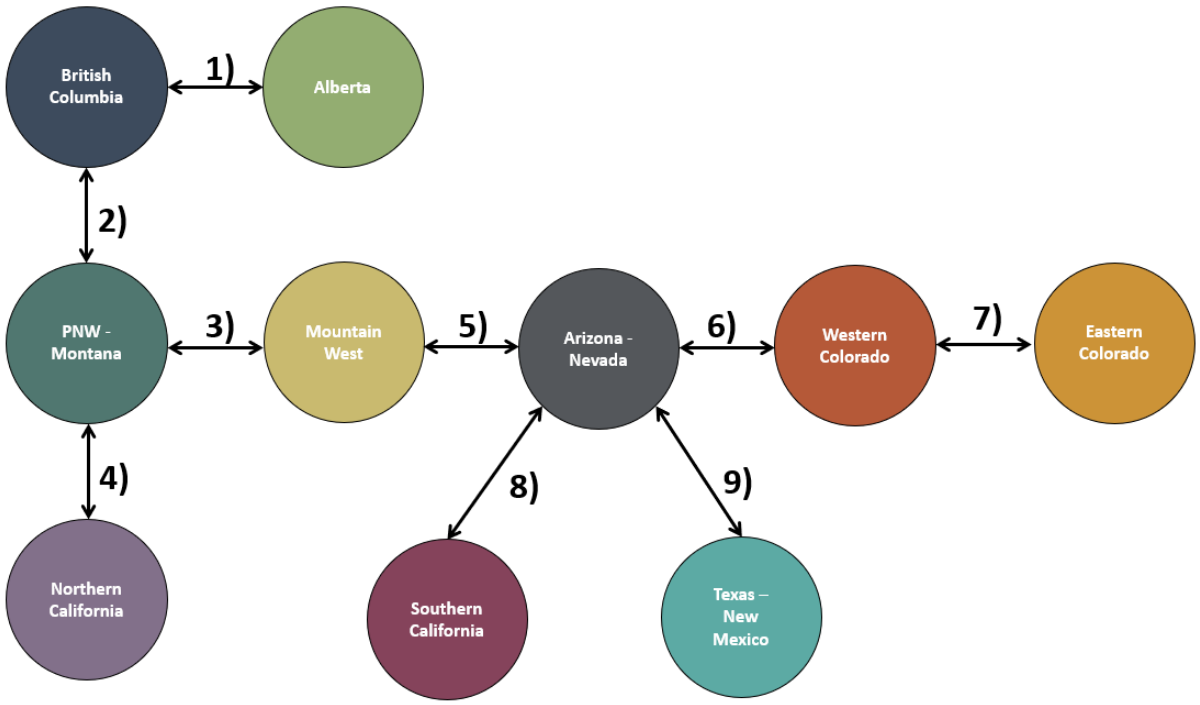
6) The Western Area Power Administration's Rocky Mountain Region (WACM) and Lower Colorado (WALC) Balancing Authorities monitor the cut plane connecting the Arizona Nevada Reserve Sharing Zone with the Western Colorado Reserve Sharing Zone,

7) The Western Area Power Administration's Rocky Mountain Region (WACM) Balancing Authority monitors the cut plane connecting the Western Colorado Reserve Sharing zone with the Eastern Colorado Reserve Sharing Zone,

8) The Imperial Irrigation District (IID) Balancing Authority monitors the cut plane connecting the Southern California Reserve Sharing zone with the Arizona Nevada Reserve Sharing Zone, and

9) The El Paso Electric Company (EPE) Balancing Authority monitors cut plane connecting the Arizona Nevada Reserve Sharing zone with the Texas New Mexico Reserve Sharing Zone.

See supporting picture of cut planes as identified above and represented between each of the zones:



Attachment M

Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Background:

This attachment (1) describes the operation and purposes of BPA Remedial Action Schemes (as defined in the NERC Glossary; also known as RAS) that are designed to drop generation and intentionally suspend Automatic Generation Control (AGC) actions to achieve the required flow mitigation effects of the RAS for transmission line outages that have large impacts to the integrity of the Western Interconnection, (2) explains why efforts by a Participating Balancing Authority or by the NWPP Reserve Sharing Group to immediately recover NWPP Reserve Sharing Group Reporting ACE following operation of this category of RAS would undermine the designed reliability benefits of the RAS, and (3) explains that the change in NWPP Reserve Sharing Group Reporting ACE that results from the planned, intentional generation dropping of these RAS is not unexpected and therefore does not meet the definition of a Balancing Contingency Event.

RAS Description:

For certain types of potential exceedances of System Operating Limits and Interconnection Reliability Operating Limits (SOL/IROL), BPA has designed RAS to intentionally drop generation and suspend related AGC actions. This category of RAS is intended to mitigate flow and stability impacts associated with various contingency events on transmission facilities. These transmission facilities are designed to operate at maximum transfer levels that rely on protection provided by the associated RAS. For example, RAS for the California-Oregon Intertie system (COI) and Pacific Direct Current Intertie system (PDCI) are in this category. There are other transmission facilities in the Northwest that also rely on this category of RAS to maximize transfer capability. Additional remedial actions for this category of RAS may include other actions such as fast switching of reactive devices and insertion of dynamic braking resistors.

This category of RAS intentionally suspends AGC within the BPA Balancing Authority and any other host Balancing Authorities of the associated generating units to avoid counteracting the intended flow mitigation benefit of the RAS. Even with AGC suspended, active governors of synchronized generators are expected to respond to the changed load-resource balance and resulting frequency drop. The Bulk Electric System within the Western Interconnection, including the affected areas, are expected to perform according to the BAL-003 requirements and immediately provide primary frequency control through governor action to arrest the frequency decline and stabilize the system.

Overall system recovery continues as the affected systems adjust transfers and generation or deploy contingency reserves, and the affected systems rebalance for the new level of transfers associated with the SOL/IROL. Each affected Balancing Authority restores its AGC once

transfers are adjusted. Generation then ramps up (receiving areas with imports curtailed) or down (sending areas with exports curtailed) to the new required levels, which enables each affected Balancing Authority to recover its Reporting ACE.

The Significance of BPA RAS in Relation to Reporting ACE:

Because certain planned generation dropping through RAS action is intended to protect affected transmission facilities within the NWPP from overloads, instability, or cascading outages, any action by Participants in the NWPP Reserve Sharing Group to immediately recover Reporting ACE following these specific RAS events may adversely affect reliability of the Bulk Electric System. Changes to the NWPP Reserve Sharing Group's Reporting ACE due to RAS actions are expected and, as such, are not Balancing Contingency Events. Generation is dispatched appropriately to accommodate the post-RAS system configuration, which may take more than 15 minutes.

BPA is responsible for notifying the WPP Staff whenever an event involving operation of this category of RAS has occurred, and therefore 15-minute recovery of NWPP Reserve Sharing Group Reporting ACE is not expected for that event.

Attachment N

Correlation Table of Participants, Reliability Coordinators, and Reserve Sharing Zones

Participant	Reliability Coordinator	Zone	Transfer Date
AESO	AESO	AB	N/A
AZPS	RC West	AZNV	11/1/2019
DEAA	SPP	AZNV	12/1/2019
AVA	RC West	PNWMT	11/1/2019
AVRN	RC West	PNWMT	11/1/2019
BANC	RC West	NCAL	7/1/2019
BCHA	BCHydro RC	BC	9/2/2019
BNBA	SPP	AZNV	7/1/2025
BPAT	RC West	PNWMT	11/1/2019
CHPD	RC West	PNWMT	11/1/2019
DOPD	RC West	PNWMT	11/1/2019
EPE	SPP	TXNM	12/13/2019
GCPD	RC West	PNWMT	11/1/2019
GRID (North)	SPP	PNWMT	12/3/2019
GRID (South)	SPP	AZNV	12/1/2019
GWA	RC West	PNWMT	11/1/20219
IID	RC West	SCAL	7/1/2019
IPC	RC West	ID	11/1/2019
NVE	RC West	HD	11/1/2019
NWMT	RC West	PNWMT	11/1/2019
PACE	RC West	PNWMT	11/1/2019

PACW	RC West	PNWMT	11/1/2019
PGE	RC West	PNWMT	11/1/2019
PSCO	SPP	ECO	12/3/2019
PNM	RC West	TXNM	11/1/2019
PSEI	RC West	PNWMT	11/1/2019
SRP	RC West	AZNV	11/1/2019
SCL	RC West	PNWMT	11/1/2019
TEP	SPP	AZNV	12/1/2019
TID	RC West	NCAL	7/1/2019
TPWR	RC West	PNWMT	11/1/2019
WACM	SPP	WCO	12/3/2019
WALC	SPP	AZNV	12/1/2019
WAUW	SPP	PNWMT	12/3/2019

DOCUMENTATION HISTORY

Updates:	Date:
NWPP Reserve Sharing Program	1-18-2006
Accommodation for new Balancing Authorities: SMUD & TID	6-07-2007
Combining of SPP and PACE zones into SPP-PACE zone	3-31-2008
Update of section D.3 for jointly owned generation	5-18-2008
Accommodation for new Balancing Authorities: GWA	10-13-2008
Updated terminology and addition of Attachments F, G, and H.	1-30-2009
Update of Attachment D to reflect tag template updates	3-31-2009
Update for requirement omission from 10-13-2008 version to 01-30-2009 version	3-31-2009
Clarity to sections I.5.l and H.2	4-8-2009
Update for computer failure, continuance to deliver reserve for full 60 minutes	4-8-2009
Clarification to Attachment B – Covered contingencies	5-12-2009
Update to Attachment B – Loss of wind generation due to temperature	7-1-2009
Grammar revision to definition of "Reportable Disturbance"	7-30-2009
Accommodation of information for the ACE Diversity Interchange (ADI) program	10-15-2009
Update of Attachment D – transmission mapping between NWMT and PGE	11-1-2009
Clarifying revisions and reorganization throughout; addition of language to Attachment B specifying Operating Committee authority to designate additional "Qualifying Events"; addition of Attachment K	10-18-2010
British Columbia Hydro and Power Authority NERC Registry acronym change from BCTC to BCHA	12-1-2010
Addition of definition of "RSG Committee"; replacement of most references to Operating Committee and all references to NWPP Reserve Sharing Subcommittee with references to RSG Committee; Updates of Attachment K	4-6-2011
Revision to Attachment B – addition of energy emergency as a Qualifying Event	10-5-2011
Update to section K.3. Financial Settlement with Powerdex Mid-Columbia Hourly	1-1-2012
Update to definition of Single Contingency, Section J.1.f with additional request language, and Section K.3. Financial Settlement clarification	6-7-2012
Revisions to Section 1.a of Attachment A to incorporate new requirements for photovoltaic and other types of generation; threshold in second bullet of	

definition of "Reportable Disturbance" lowered from 190 MW to 170 MW and updates to Attachment K Tables 1 and 3 1-10-2013

Clarifying updates throughout document including the addition of Section D.3.f, revisions to Sections E.2, E.4, F and updates to Attachments B, C, F and K 4-4-2013

Update to Attachment B and removal of (e) Unexpected loss of Contingency Reserve with new language to section (c) 6-6-2013

Updates to Attachments D, H, and K for incorporation of the NaturEner Wind Watch BA, WWA into program documentation 10-30-2013

Updates to Attachments D, H, and K for incorporation of the Constellation Energy Control and Dispatch BA, WWA into program documentation along with other clarifying updates throughout the document 11-25-2013

Updates to Attachments C, D, H, and K to reflect Nevada Power Company (NEVP), as operator of the consolidated Balancing Authority Area encompassing the Balancing Authority Areas previously operated separately by Sierra Pacific Power Company (SPPC) and Nevada Power Company (NEVP) 1-9-2014

Revisions throughout document to reflect implementation of WECC Standard BAL-002-WECC-2, to incorporate terms governing Loss of a Unit-Contingent Purchase, and to reflect the name change of the organization formerly known as Constellation Energy Control and Dispatch (CSTO) to Gridforce Energy Management, LLC (GRID) 8-15-2014 – Effective 10-1-2014

Revisions to incorporate language concerning RSG compliance with R3 and R4 of WECC BAL-002-WECC-2 8-22-2014 – Effective 10-1-2014

Clarifying revisions to the description of Contingency Reserve Obligation calculation in Attachment A, with conforming changes in body of document and other minor clean-up items 1-8-2015

Clarifying revisions to timing of requests for assistance reserve in section E.3; changes to section I.2, Major Transmission Facility Information; Attachment A, revisions regarding Balancing Authority Calculation of Contingency Reserve Obligation When Communications with Reserve Sharing Computer System Are Disrupted; and a new Attachment L, Transmission Facilities Making up Cut Planes Between Reserve Sharing Zones 4-2-2015

Clarifying revisions to section K.3.e to address how and when the NWPP Staff will complete and post calculations of applicable settlement prices 4-17-2015 – Effective 5-1-2015

Revisions to "Introduction and Overview" section to clarify that NWPP Staff are responsible for compliance reporting, not individual Participants; revisions to Section D.4.b to require at least quarterly reporting of data for R.3. and R.4 of WECC Standard BAL-002-WECC-2	10-8-2015
Addition and incorporation of the defined term "Contingency Reserve Available" and editorial cleanup revisions	4-1-2016
Clarifications related to NWPP Reserve Sharing Program participation status, determining real-time Most Severe Single Contingency, and reflection of NWPP Reserve Sharing Program requirements in Participant operating procedures	10-13-2016
Removal of language in Attachment B Qualifying Events, (d) Declaration of Energy Emergency Alert 2 or 3	05-12-2017
Effective May 12, 2017 - Participation in WECC Field Test Waiving Enforcement of BAL-002-WECC-2a, Requirement R2	05-12-2017
Revisions to harmonize definitions and other relevant provisions to NERC Standard BAL-002-2(i) and the NERC Glossary; miscellaneous cleanup and clarifying revisions	10-25-2017
Newly added definition for Operating Plan, clarifying changes to MSSC definition, and conforming changes sections D. 3., E.4. and L.	11-30-2017
Clarifying changes to term Reserve Sharing Zone, addition of terms: System Operator, BAA Net Generation, Net Generation, Actual Net Interchange, Scheduled Net Interchange; clarifying changes to Sections D.3.j, revisions to Section I.1,, addition of Section I.5.d., clarifying changes to Attachment A of BAA Net Generation, Net Generation, Actual Net Interchange, Scheduled Net Interchange; revisions to Attachments D, H, and K to reflect addition of Avangrid Renewables as a new Participant. Changes to update the WECC and NERC BAL-002 standards to conform through the entire document.	5-10-2018
Clarifying changes to section D.3.k. to clarify NWPP RSG procedures related to Energy Emergency Alerts. In addition, clarifying language was added to Section L. regarding Obligation to submit a NWPP RSG Verification Form and new Section L.2. added regarding Reporting Balancing Obligation to Notify NWPP Staff.	11-8-2018

New term added for NWPP Reserve Sharing Group Reporting ACE. In addition, new Attachment M – *Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE* and Attachment N -

Correlation Table of Participants, Reliability Coordinators and Zones. Clarifying changes to section I.5. regarding data telemetered from Reserve Sharing Program to the Reliability Coordinator with the addition of the NWPP RSG Reporting ACE and new Section I.6. – Management of Data Related to Reserve Sharing Zones. 2-14-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 2-14-2019

Clarifying notes to Attachment B - Qualifying Events with new *note 2* and formatting (similar to NERC Definition for Balancing Contingency Event). Additional housekeeping items to clarify front page with BAL-002-WECC-2a, Section H.3. with updated contact information, corrected bulleting in Attachment A, and updated Attachment L with appropriate AESO Cut Plane facilities. 5-16-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 5-16-2019

Clarification to WECC Waiver regarding BAL-002-WECC-2a R2. Balancing Contingent Event term added and conforming changes throughout document for a Reportable Balancing Contingent Event. Reporting ACE clarification to Section I.1.f. and J.2.a. Language added to section L.1 to address RSG reporting of EEAs. Clarification of zones to response levels to Attachment C, including new tables for zones and associated BAs along with responding levels. In addition, the removal of Attachment D with new reference to NWPP RSG Tag Templates and conforming changes. Housekeeping changes to conform document with Attachment N. 7-1-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 7-1-2019

Updates to address the addition of new BA Participants, WACM and PSCO for live operation 9-3-2019. Conforming changes throughout document (Section I.2., I.4.d., Attachment C, Attachment H, Attachment K, Attachment L, and Attachment N). 7-1-2019 – effective 9-3-2019

Revisions to Attachment M by removing "Reportable" from references to Balancing Contingency Event. 8-8-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-8-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-7-2019

Clarifications made to section E.3. Timing of Requests for Assistance Reserve. Additions to section H.3. with respect providing ICCP failover notifications to NWPP staff. Revisions to section I.5. regarding Data Telemetered to the RCs and elimination of section I.6 as it is all covered in the revised section I.5. Revisions to section K. Settlement with the elimination of Energy In-Kind settlement and conforming changes. 11-7-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 2-6-2020

Housekeeping update to WECC Waiver extension to BAL-002-WECC-2a R2 on front page. 4-6-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Housekeeping update to font formatting and indexing. Addition of Process Diagrams as Attachment D (General Process Diagram, Settlement Process, Calculation of CRO, and Back-up Procedures). Consistent naming of generator contingencies in Attachment K. 5-7-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Revised Section B. term for *Participating Balancing Authority or Participant*. Revisions to Section C.3. to address Balancing Authority versus Balancing Authority Area and program functionality. Revisions to Section F. to further clarify program functionality for commitment of Contingency Reserve Obligation when requesting Assistance Reserve, including conforming changes to Section I.4.d. and elimination of Section 2. *Discretion of Participating BA to Carry More Contingency Reserve Than Required by Calculation of Minimum Contingency Reserve Obligation; Obligation to Make All Reported Contingency Reserve Available*. Section I.1. revision and addition of new data from Participant BAs to program (BA_FBS, BA_Ime, BA_ATEC, and BA_ADI). Updates to section L. as related to Internal RSG Reporting. Revisions to Attachment A, Section 1. to address program update to MSSC Deadbands. Attachment K MSSC Updates to PGE MSSC. 11-5-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Housekeeping update to font formatting and indexing. Revisions to Section B. Terminology's *BAL-002* term. Revisions to Sections E.2. regarding actions required to respond to an EEA. Revisions to Section

E.3. regarding length of time for accessing Contingency Reserve to respond to EEAs. Conforming changes to address Section B. *Contingency Reserve Available* term relating to EEA. Last, updates to Section I.1. h. & i. to reflect correct use of NI_A and NI_S. 2-4-2021

Updated language to Section H.2. to for NWPP Staff to perform analysis on each Reportable Balancing Contingency Event that the NWPP RSG experiences. 3-30-2021

Updated cover page to reflect WECC-0115 BAL-002-WECC-2a, Requirement R2, Compliance Waiver Extension 4-6-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Revisions to section D.2. to address appropriate reference to Attachment A and its sections. Revisions to Attachment A. 1 to remove the 1.5 shortfall multiplier to address the current functionality of computer program. 5-6-2021

RSGC approved updates (Feb. 4, 2021) to conform documentation with new Standard BAL-002-WECC-3, effective June 28, 2021 6-28-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-5-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Clarifying changes to Contingency Reserve Available (CRA) term, clarifying changes to NWPP Reserve Sharing Group Reporting ACE term, clarifying changes to Section D.3.i - ACE recovery period and size, clarifying changes to Section I.3.j. & k to address calculation of Reporting ACE, addition to Section F. regarding metrics for Deployment of Contingency Reserve, clarifying changes to Section H. regarding Participant responsibilities related BA footprint changes to MSSC (Unit configuration, RAS, etc.), and update to Section K.2.c. regarding annual review period. 11-5-2021

Updates to Section H. to address clarifications to Roles and Responsibilities of the Participant, NWPP Staff with on-call support 24x7, and RSG Committee. 1-12-2022

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Addition of new to Sections I.4. p. and I.4.q. as approved in 2018.11.09. 2-3-2022

Updated Attachment K Tables with new Table 4 to address AVRN's new Gold Hills Wind Project

connected to BPA transformer. 3-11-2022

Housekeeping from NWPP to WPP (*NWPP doing business as WPP*), including associated email addresses. Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 5-5-2022

Updated Attachment K Tables with PAC transfer of Jim Bridger from PACW to PACE BAA, updating new MSSCs for both, effective July 6, 2022 6-29-2022

More conforming updates to address NWPP to WPP. New Section E.3. and conforming changes to address performance metric for deployment of Contingency Reserve. Updates to Section K.2. Financial Settlement from use of Powerdex to the Intercontinental Exchange (ICE) in October 2022 (Mid-Columbia and Palo Verde). Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-4-2022

Section B. Clarifying updates CRA Definition and conforming updates to Section D.3.b., Section E.2. and Section J.1. Section B. new term: 'Recovery Reporting ACE Target'. Performance Metric updates to Section E.4 and F. Clarifying updates to section K.2.Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-3-2022

Attachment K Tables updated with GCPD MSSC to Tables 1 - Priest Rapids and Table 3 - Wanapum. 12-21-2022

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 with GCPD MSSC and clarifying change to term 'Recovery Reporting ACE Target' 2-2-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 Colstrip Capacity Numbers, Table 2 Valmy Shares, and Table 3 AESO Plant Capability, 5-4-2023

Updated NaturEner Attachment H with NaturEner Balancing Authority Name change to BHEM Power Watch, LLC and BHEM Wind Watch, LLC 5-5-2023

Updated Qualifying Events from all EEAs to EEA3 only – Deleted previous section D.3.k (Script for talking to RC to prevent unnecessary EEAs). Clarifications to Sections E.2

., E.3. Attachment B.

6-8-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-3-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 for PACE and GCPD along with Table 3 for PACE. 11-2-2023

Updates to conform documentation with zonal transition from Idaho and High Desert Zones to Mountain West and Arizona Nevada Zone to Section I.2., Attachments C, K, L & N. 1-24-2024

Clarifying language added to Section F, newly added Section P – Penalties for Non-Performance (Effective July 1, 2024), and conforming changes to Section I.4.c. In addition, reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 Rocky Reach-River Crossing 7-8-9 Participants. 2-8-2024

Conforming changes with the addition of the new Balancing Authority Participants (AZPS, DEAA, EPE, IID, HGMA, PNM, SRP, TEPC, WALC) effective May 1, 2024 to Attachment C, Attachment H, Attachment K, Attachment L updates and conforming changes to Section I.2., and Attachment N. In addition, consistency with use of term 'RSG Committee', removal of standards documentation to Attachment I NERC BAL-002 and Attachment J BAL-002-WECC. 3-20-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 for BANC and TEPC 5-17-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-8-2024

Updates to Section P for a review process to allow for partial credit, to provide clarity that an entity may still receive credit for the "clock-minute averages" independently of meeting the Recovery Reporting ACE Target criteria. In addition, reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining

system reliability. 11-7-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Program Documentation with new terms: Balancing Authority Area MSSC, Long-Term Zonal MSSC Limit, and NWPP Reserve Sharing Group Long-Term MSSC Limit. Conforming changes to Section M to address MSSC limits, and conforming changes to Attachment K Table 1 with Maximum Allowable Zonal MSSC and NWPP RSG Long-Term MSSC Limit. 2-6-2025

Review and update to Attachment K, 1. column header from BAA MSSC MW to BAA System Normal MSSD MW. 2-12-2025

Conforming changes with the consolidation of HGMA BA into SRP BA, effective June 1, 2025, the addition of the new First LightEnergy, LLC BA (BNBA), effective July 1, 2024 to Attachment C, Attachment H, Attachment K, Attachment N. 7-1-2025

Updates to Attachment K, 1. BAA MSSC for NEVP and 2., adding back Jim Bridger for PACE and IPC. 9-23-2025

Conforming changes with the consolidation of BHE Montana's WWA BA into the GWA BA, effective October 1, 2025. 10-1-2025

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	)

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

Exhibit 2-146:
Western Frequency Response Sharing Group

WESTERN FREQUENCY RESPONSE SHARING GROUP

As permitted by the NERC Standard, BAL-003-2, many Balancing Authorities within the Northwest Power Pool Area have instituted the Western Frequency Response Sharing Group (WFRSG). By collectively participating in the WFRSG, participants are entitled to calculate their annual Frequency Response Measure (FRM) in aggregate to achieve an FRM that is equal to or more negative than its' (the WFRSG) FRO to assure sufficient Frequency Response is provided to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

MORE INFO

NOTIFY ME

DOCUMENTS | VIEW ALL

WFRSG - WFRSGC

WFRSG Agenda and Meeting Materials

WFRSG Agenda and Meeting Materials

LOCKED

WFRSG - WFRSGC

2024 Q3 Updates - FRS Form 1 and FRS Form 2

LOCKED

WFRSG - WFRSGC

2024 Q2 Updates - FRS Form 1 and FRS Form 2

LOCKED

MANAGER



ChaRee DiFabio
RSGC & WFRSG Manager
WPP | 503-445-1079
charee.difabio@westernpo...

WFRSG PARTICIPANTS











































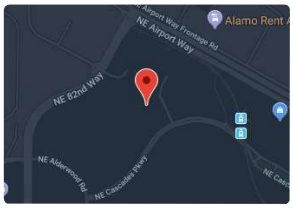






WPP HEADQUARTERS

7525 NE Ambassador Place, Suite M
Portland, Oregon, 97220
(503) 445-1074



PROGRAMS

NEWS

EVENTS

DOCUMENTS

ABOUT

SIGN IN

WESTERN

CONTACT

© 2026 WPP | All rights reserved. | Terms of Use | Anti-trust Compliance

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	)

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

Exhibit 2-147:
WRAP Tariff

WESTERN RESOURCE ADEQUACY PROGRAM

TARIFF

OF

NORTHWEST POWER POOL

D/B/A

WESTERN POWER POOL

TABLE OF CONTENTS

PART I GENERAL PROVISIONS
1. Definitions
2. Role of Western Power Pool
3. Role of the Board of Directors and Limitations on Board Authority
4. Organizational Groups for the WRAP
5. Independent Evaluator
6. WPP Invoicing and Settlement
7. Credit Requirements and Settlement for Holdback and Delivered Energy
8. Force Majeure, Limitation of Liability, and Indemnification
9. Dispute Resolution Procedures
10. Treatment of Confidential and Commercially Sensitive Information of Participants
11. Timing
12. Application and Registration

PART II FORWARD SHOWING PROGRAM
13. Overview
14. Forward Showing Program Process and Timeline
15. Transition Period
15A Non-Binding Seasons
16. Components of the Forward Showing
17. Forward Showing Deficiency Charge

PART III OPERATIONS PROGRAM
18. Operations Program Overview
19. Operations Program Timeline and Supporting Information
20. Components of the Operations Program
21. Operations Program Settlements

SCHEDULE 1
WESTERN RESOURCE ADEQUACY PROGRAM ADMINISTATIVE COST RECOVERY CHARGE

ATTACHMENT A
Western Resource Adequacy Program Agreement

PART I GENERAL PROVISIONS

1. Definitions

Unless the context otherwise specifies or requires, capitalized terms used in this Tariff shall have the respective meanings assigned herein for all purposes of this Tariff (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Parts, Sections, Schedules, or Attachments, are to Parts, Sections, Schedules, or Attachments of this Tariff.

Applicable Price Index: A published index of wholesale electric prices, or Locational Marginal Prices duly calculated and posted by a FERC-regulated market operator, in either case as designated under Part III of this Tariff for use in connection with an identified Subregion.

Administration Charge or WRAP Administration Charge: The charge established under Schedule 1 of this Tariff for recovery of the costs of the WRAP.

Advance Assessment: Analyses and calculations of Participant load, resource, and other information performed in advance of each Binding Season as set forth in Part II of this Tariff.

Aggregate Capacity Deficiency: As to a Binding Season, the sum of the maximum Monthly Deficiencies of all Participants that submitted FS Submittals for such Binding Season, as determined following completion of the Cure Period for such Binding Season.

Available Transfer Capability ("ATC"): Transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Base Charge: A component of the WRAP Administration Charge as established under Schedule 1 of this Tariff.

Base Costs: Base Costs shall have the meaning provided in Schedule 1 of this Tariff.

Base Services Cost Centers: The cost centers comprising the Base Charge as defined in Schedule 1 of this Tariff.

Base Services Percentage: Base Services Percentage shall have the meaning provided in Schedule 1 of this Tariff.

Binding Season: The Summer Season or the Winter Season.

Board of Directors or Board: The Board of Directors of the Northwest Power Pool d/b/a Western Power Pool.

Business Day: Any Day that is a Monday through Friday, excluding any holiday established by United States federal authorities.

Business Practice Manuals: The manuals compiling further details, guidance, and information that are appropriate or beneficial to the implementation of the rules, requirements, and procedures established by this Tariff. Business Practice Manuals do not include such internal rules or procedures as the Western Power Pool may adopt for its operation and administration, including but not limited to any corporate by-laws of the Western Power Pool, or for any services or functions provided by the Western Power Pool other than those established by this Tariff.

CAISO: The California Independent System Operator Corporation, a California nonprofit public benefit corporation.

Capacity Benefit Margin: An amount of transmission transfer capability permitted under open access transmission rules to be reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Capacity Critical Hours ("CCH"): Those hours during which the net regional capacity need for the WRAP Region is expected to be above the 95th percentile, based on historical and synthesized data for the WRAP Region's gross load, variable energy resource performance, and interchange.

Capacity Deficiency: A shortfall in a Participant's Portfolio QCC relative to that Participant's FS Capacity Requirement, as further defined in Part II of this Tariff.

Cash Working Capital Fund: Cash Working Capital Fund shall have the meaning provided in Schedule 1 of this Tariff.

Cash Working Capital Support Charge: A charge assessed to Participants under Schedule 1 of this Tariff to fund the Cash Working Capital Fund.

Cash Working Capital Support Charge Rate: Cash Working Capital Support Charge Rate shall have the meaning provided in Schedule 1 of this Tariff.

Central Hub: A designated point or named group of points on the transmission system within a Subregion identified by the Program Administrator that permits energy deliveries from multiple points within such Subregion.

Cost of New Entry ("CONE"): The estimated cost of new entry of a new peaking natural gas-fired generation facility, as determined under, and used in, Part II of this Tariff.

CONE Factor: A factor employed in the calculation of Deficiency Charges under Part II of this Tariff, to reflect whether, and the extent to which, the WRAP Region as a whole is expected to have a capacity deficiency during the period for which the Deficiency Charge is being calculated or a factor employed when a Participant has had repeated deficiencies in sequential years.

Committee of State Representatives ("COSR"): Committee of State Representatives, as established in Part I of this Tariff.

Contingency Reserve: As more fully described in the NERC WECC reliability standards, a quantity of reserves, consisting of generation, load, interchange, or other resources, that are deployable within ten minutes, equal to the greater of (i) the MW quantity of the loss of the most severe contingency and (ii) the megawatt quantity equal to the sum of 3% of hourly integrated load plus 3% of hourly integrated generation.

Critical Mass: *The threshold level of participation in a Subregion, as established in the Business Practice Manuals, below which each Participant of such Subregion may elect to participate as a Non-Binding Participant.*

Cumulative Delivery Failure Period: Any period of five consecutive years, ending with and including the most recent Energy Delivery Failure as of the time of determination of a possible Delivery Failure Charge.

Day: A calendar day.

Day-Ahead Price: A price for wholesale electric transactions designated as a day-ahead price in an Applicable Price Index.

Default Allocation Assessment: A charge assessed on non-defaulting Participants to recover the costs associated with a default by a Participant, as set forth in Part I of this Tariff.

Deficiency Charge: A charge assessed for a Capacity Deficiency or Transmission Deficiency, as set forth in Part II of this Tariff.

Delivery Failure Charge: A charge assessed for a Participant's failure to deliver a required Energy Deployment, as set forth in Part III of this Tariff.

Delivery Failure Charge Rate: A rate employed in the determination of a Delivery Failure Charge as more fully set forth in Part III of this Tariff.

Delivery Failure Factor: A factor used in the determination of a Delivery Failure Charge to recognize the relative severity or impact of an Energy Delivery Failure, as set forth in Part III of this Tariff.

Demand Response: A quantifiable load reduction or otherwise controllable load for which a Participant has two mutually-exclusive options to use to affect its FS Capacity Requirements in a FS for a Binding Season: (1) leave the effects of historically deployed demand response as part of its load provided for the Advance Assessment; or (2) utilize as a Demand Response Capacity Resource.

Demand Response Capacity Resource: A Qualifying Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements established under Part II of this Tariff utilized to meet a Participant's FS Capacity Requirement.

Demonstrated FS Transmission: A Participant's demonstration in its Forward Showing Submittal that it has secured firm transmission service rights of the type and quantity sufficient to provide reasonable assurance, as of the time of the Forward Showing Submittal, of delivery of

capacity from the Qualifying Resources and the resources associated with the power purchase agreements in the Participant's Portfolio QCC.

Discounted Deficiency Change: *A reduced Deficiency Charge during the Transition Period that enables a deficient Participant that demonstrates commercially reasonable efforts but is unable to cure deficiencies to access Operations Program capacity.*

Dual Benefit Cost Centers: Dual Benefit Cost Centers shall have the meaning provided in Schedule 1 of this Tariff.

Effective Load Carrying Capability ("ELCC"): A methodology employed to determine the Qualified Capacity Contribution of certain types of Qualifying Resources, as more fully set forth in Part II of this Tariff.

Energy Declined Settlement Price: A pricing component used as part of the calculation of settlements for Holdback Requirements and Energy Deployments under Part III of this Tariff.

Energy Delivery Failure: A failure by a Participant to provide an Energy Deployment assigned to such Participant under Part III of this Tariff.

Energy Deployment: A delivery of energy that a Participant is required to provide during an Operating Day, as set forth in Part III of this Tariff.

Energy Storage Resource: A resource, not including a Storage Hydro Qualifying Resource, designed to capture energy produced at one time for use at a later time.

Excused Transition Deficit: A Participant's inability during the Transition Period to demonstrate full satisfaction of the Participant's FS Capacity Requirement, which, under certain conditions and limitations prescribed by Part II of this Tariff, permits *the Participant to pay a Discounted* Deficiency Charge.

Federal Power Marketing Administration: A United States federal agency that operates electric systems and sells the output of federally owned and operated hydroelectric dams located in the United States.

FERC: The Federal Energy Regulatory Commission.

Forced Outage Factor: The factor resulting from dividing the number of hours a generating unit or set of generating units is not synchronized to the grid system, not in reserve shutdown state and considered to be out of service for unplanned outages—or a startup failure, by the number of total hours in the period multiplied by 100% or a Program Administrator calculated equivalent forced outage factor that reflects the likelihood and extent to which a resource will be unavailable from time to time due to factors outside management control.

Forward Showing Program: The program and requirements as set forth in Part II of this Tariff.

Forward Showing Submittal ("FS Submittal"): The submissions a Participant is required to submit in advance of each Binding Season to demonstrate its satisfaction of the FS Capacity Requirement and FS Transmission Requirement, as set forth in Part II of this Tariff.

Forward Showing Year: A period consisting of a Summer Season and the immediately succeeding Winter Season.

FS Capacity Requirement: The minimum quantity of capacity a Participant is required to demonstrate for a Binding Season, as set forth in Part II of this Tariff.

FS Deadline: The deadline for Participants' submissions of their FS Submittals for a Binding Season, as established under Part II of this Tariff.

FS Planning Reserve Margin ("FSPRM"): An increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, or lower availability of resources, expressed as a percentage of the applicable peak load forecast, as determined in accordance with Part II of this Tariff.

FS Transmission Requirement: The minimum quantity of transmission service rights a Participant is required to demonstrate for a Binding Season, as set forth in Part II of this Tariff.

High-Priced Day: The most recent day in the CAISO in which prices in the day-ahead market were at least $200/MWh.

Holdback Capacity: Capacity that is voluntarily supplied or is the result of a positive Sharing Calculation result that is bindingly committed to the WRAP after it is claimed by one or more Participants with a negative Sharing Calculation result.

Holdback Requirement: A MW quantity, as determined on a Preschedule Day, that a Participant is required to be capable of converting into an Energy Deployment on a given hour of the succeeding Operating Day, as more fully set forth in Part III of this Tariff.

ICE Index: A wholesale electric price index prepared and published by the Intercontinental Exchange.

Incremental Cash Working Capital Support Charge: Incremental Cash Working Capital Support Charge shall have the meaning provided in Schedule 1 of this Tariff.

Independent Evaluator: An independent entity engaged to provide an independent assessment of the performance of the WRAP and any potential beneficial design modifications, as set forth in Part I of this Tariff.

Installed Capacity: Nameplate capacity adjusted for conditions at the site of installation.

International Power Marketing Entity: An entity that (i) owns, controls, purchases and/or sells resource adequacy supply and is responsible under the WRAP program for meeting LRE obligations associated with one or more loads physically located outside the United States.

Legacy Agreement: A power supply agreement entered into prior to October 1, 2021.

Load Charge: A component of the WRAP Administration Charge as established under Schedule 1 of this Tariff.

Load Charge Rate: Load Charge Rate shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Costs: Load Services Costs shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Cost Centers: Load Services Cost Centers shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Percentage: Load Services Percentage shall have the meaning provided in Schedule 1 of this Tariff.

Load Responsible Entity ("LRE"): An LRE is an entity that (i) owns, controls, purchases and/or sells resource adequacy supply, or is a Federal Power Marketing Administration or an International Power Marketing Entity, and (ii) has full authority and capability, either through statute, rule, contract, or otherwise, to:

(a) submit capacity and system load data to the WRAP Program Operator at all hours;

(b) submit Interchange Schedules within the WRAP Region that are prepared in accordance with all NERC and WECC requirements, including providing E-Tags for all applicable energy delivery transactions pursuant to WECC practices and as required by the rules of the WRAP Operations Program;

(c) procure and reserve transmission service rights in support of the requirements of the WRAP Forward Showing Program and Operations Program; and

(d) track and bilaterally settle holdback and delivery transactions.

Subject to the above-mentioned criteria, an LRE may be a load serving entity, may act as an agent of a load serving entity or multiple load serving entities, or may otherwise be responsible for meeting LRE obligations under the WRAP.

Locational Marginal Price: The cost of delivering an additional unit of energy to a given node, as calculated under a FERC-regulated wholesale electric tariff.

Loss of Load Expectation ("LOLE"): An expression of the frequency with which a single event of failure, due to resource inadequacy, to serve firm load would be expected (based on accepted reliability planning analysis methods) to result from a given FS Planning Reserve Margin.

Make Whole Adjustment: A component used as part of the calculation of settlements for Holdback Requirements and Energy Deployments under Part III of this Tariff.

Maximum Base Charge: The maximum amount prescribed in Schedule 1 of the Tariff that the Base Charge cannot exceed.

Maximum Load Charge Rate: The maximum rate prescribed in Schedule 1 of the Tariff that the Load Charge Rate cannot exceed.

Median Monthly P50 Peak Loads: Median Monthly P50 Peak Loads has the meaning prescribed by Schedule 1 of this Tariff.

Month: A calendar month.

Monthly Capacity Deficiency: A Participant's Capacity Deficiency for a given Month.

Monthly Deficiency: An identification under Part II of this Tariff whether, and the extent to which, a Participant's need for capacity or transmission for a given Month is greater than the capacity or transmission, respectively, the Participant can demonstrate for such Month.

Monthly FS Capacity Requirement: FS Capacity Requirement determined as to a Month.

Monthly FSPRM: The FS Planning Reserve Margin applicable to a given Month of a given Binding Season, as determined in accordance with Part II of this Tariff.

Monthly Transmission Deficiency: A Participant's Transmission Deficiency for a given Month.

Monthly Transmission Demonstrated: A Participant's Demonstrated FS Transmission for a given Month.

Monthly Transmission Exceptions: Exceptions from the FS Transmission Requirement approved under Part II of this Tariff for a Participant for a given Month.

Multi-Day-Ahead Assessment: A period of days preceding each Operating Day, and ending on the Preschedule Day, during which Sharing Calculations are successively performed based in each case on Operating Day conditions expected at the time of calculation.

North American Electric Reliability Corporation ("NERC"): A not-for-profit international regulatory authority that serves as the designated electric reliability organization for the continental United States, Canada, and a portion of Mexico.

Net Contract QCC: The QCC, which may be a positive or negative value, calculated, in sum and on net, for a Participant's power purchase agreements and power sale agreements, in accordance with Part II of this Tariff.

Non-Binding Season: As to a Participant, *any* Binding Season during which the *provisions of Section 15A.1* of this Tariff *apply*.

Non-Binding Participant: For any Binding Season, a Participant that has made an election by which such Binding Season is a Non-Binding Season for that Participant.

Open Access Transmission Tariff: A governing document on file with FERC establishing the rates, terms, and conditions of open access transmission service, or equivalent tariff of a transmission service provider that is not required to file its transmission service tariff with FERC.

Operating Day: A current Day of actual electric service from resources to load, for which Sharing Events are determined and Energy Deployments may be required, as set forth in Part III of this Tariff.

Operations Program: The program and requirements set forth in Part III of this Tariff.

P50 Peak Load Forecast: A peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast.

Participant: A Load Responsible Entity that is a signatory to the WRAPA.

Portfolio QCC: As to a Participant, the sum of the Resource QCC provided by all of a Participant's Qualifying Resources plus the Net Contract QCC of such Participant, as adjusted to reflect RA Transfers as described in Section 16.2 7 and Planned Outages as described in Section 16.2.8.

Preschedule Day: The applicable scheduling Day for a given Operating Day as defined in scheduling calendar established by WECC.

Program Administrator: The Western Power Pool, in its role as the entity responsible for administering the WRAP.

Program Operator: A third party that has contracted with the Program Administrator to provide technical, analytical, and implementation support to the Program Administrator for the WRAP.

Program Review Committee ("PRC"): The stakeholder sector committee as established in Section 4.2 of this Tariff.

Pure Capacity: A MW quantity of capacity without any assigned forced outage rate employed in ELCC determinations under Part II of this Tariff.

Qualifying Capacity Contribution ("QCC"): The MW quantity of capacity provided by a resource, contract, or portfolio which qualifies to help satisfy a Participant's FS Capacity Requirement, as determined in accordance with Part II of this Tariff.

Qualifying Resource: A generation or load resource that meets the qualification and accreditation requirements established by and under Part II of this Tariff.

Real-Time Price: A price for wholesale electric transactions designated as a real-time price in an Applicable Price Index.

Resource Adequacy Participant Committee ("RAPC"): The committee comprised of representatives from each Participant as established in Part I of this Tariff.

Resource QCC: The QCC provided by a Qualifying Resource, as determined in accordance with Part II of this Tariff.

Run-of-River Qualifying Resource ("ROR"): A hydro-electric power project that does not have the capability to store a sufficient volume of water to support continuous generation at the project's stated maximum capacity for a period of one hour. Resource does not meet the definition of a Storage Hydro Qualifying Resource.

Safety Margin: An additional factor allocated among Participants with positive sharing calculations when warranted by certain conditions as prescribed by Part III of this Tariff.

Senior Official Attestation: A signed statement of a senior official of a Participant attesting that it has reviewed such Participant's information submission required under this Tariff, that the statements therein are true, correct and complete to the best of such official's knowledge and belief following due inquiry appropriate to the reliability and resource adequacy matters addressed therein, and containing such further statements as required by this Tariff or the applicable Business Practice Manual for the information submission at issue.

Sharing Calculation: A calculation used in the Operations Program under Part III of this Tariff to identify any hour in which any Participant is forecast to have a capacity deficit.

Sharing Event: An hour or hours of an Operating Day for which one or more Participants has a negative Sharing Calculation result, as determined in accordance with Part III of this Tariff.

Storage Hydro Qualifying Resource: A hydro-electric power project with an impoundment or reservoir located immediately upstream of the powerhouse intake structures that can store a sufficient volume of water to support continuous generation at the project's stated maximum capacity for a period of one hour or longer.

Subregion: An area definition approved by the Board of Directors and identified in the Business Practice Manuals, that is wholly contained within the WRAP Region, which is separated from one or more other Subregions by transmission constraints on capacity imports or on capacity exports that result, or are expected to result, in differing FSPRM determinations for that Subregion relative to such other Subregion.

Summer Season: A period of time that commences on June 1 of a Year and terminates on September 15 of the same Year.

System Sale: A bilateral agreement that conveys generating capacity from a group of generating resources from one party to another.

Transition Period: The Binding Seasons within the time period from June 1, 2025, through March 15, *2029*, plus the time period required to implement the requirements and procedures of Part II of this Tariff applicable to such Binding Seasons.

Transmission Deficiency: A shortfall in a Participant's demonstration of secured transmission service rights, after accounting for any approved transmission exceptions, relative to that Participant's FS Transmission Requirement, as further defined in Part II of this Tariff.

Unforced Capacity: The percentage of Installed Capacity available after a unit's forced outage rate is taken into account.

Variable Energy Resource ("VER"): An electric generation resource powered by a renewable energy source that cannot be stored by the facility owner or operator and that has variability that is beyond the control of the facility owner or operator, including but not limited to a solar or wind resource.

VER Zone: A geographic area delineated in accordance with Section 16.2.5.2 of this Tariff for a given type of VER, where each VER of that type located in such area is anticipated to be comparably affected by meteorological or other expected conditions in such area to a degree that warrants distinct calculation of ELCC allocations for such VERs of that type in such area.

Voluntary Holdback: Capacity that is offered to the Operations Program by a Participant with excess supply that is not obligated to the WRAP through a positive Sharing Calculation result, some or all of which can used as part of the offering Participant's Holdback Requirement. For a Participant in a Subregion without a Central Hub, Voluntary Holdback for an hour must additionally include a total quantity for all identified points from Section 19.4 at which it can deliver that is no less than the amount of the Voluntary Holdback capacity for such hour.

Western Electricity Coordinating Council ("WECC"): A non-profit corporation that has been approved by FERC as the regional entity for the western interconnection and that also has NERC delegated authority to create, monitor, and enforce reliability standards.

Western Resource Adequacy Program Agreement ("WRAPA"): The participation agreement for the Western Resource Adequacy Program, as set forth as Attachment A to this Tariff, or as set forth for an individual Participant in a non-conforming version of such participation agreement accepted by FERC.

Western Resource Adequacy Program ("WRAP"): The Western Resource Adequacy Program, as established under this Tariff.

Western Power Pool ("WPP"): Northwest Power Pool, d/b/a Western Power Pool, which serves as Program Administrator for the WRAP under this Tariff and holds exclusive rights under section 205 of the Federal Power Act to file amendments to this Tariff.

Winter Season: A period of time that commences on November 1 of a Year and terminates on March 15 of the immediately following Year.

WRAP Cost Assignment Matrix: The matrix set forth in Schedule 1 of this Tariff to identify which WRAP costs are assessed to the Base Charge and the Load Charge components of the WRAP Administration Charge.

WRAP Region: The area comprising, collectively, (i) the duly recognized and established load service areas of all loads in the United States that all Participants are responsible for serving, (ii) the duly recognized and established load service areas of all loads in the United States that all load serving entities, on whose behalf a Participant acts in accordance with this Tariff, are responsible for serving, and (iii) the applicable location(s) on the United States side of the United States

international border that form the basis for an International Power Marketing Entity's participation under the WRAP, in all cases excluding, for any Binding Season, any loads permitted by this Tariff to be excluded from Participants' Forward Showing Submittal for such Binding Season.

Year: A calendar year.

2. Role of Western Power Pool

2.1 WPP, acting under the direction of its Board of Directors, shall administer the WRAP as Program Administrator. Except as specified in Section 3 of this Tariff, WPP, as authorized by its Board of Directors, shall have the sole authority to submit to FERC amendments to the rates, terms, and conditions set forth in this Tariff under section 205 of the Federal Power Act, 16 U.S.C. § 824d. Nothing contained herein shall be construed as affecting in any way the right of any Participant or any other entity to apply to FERC for amendments to the rates, terms, and conditions contained herein under section 206 of the Federal Power Act, 16 U.S.C. § 824e, or any other applicable provision of that Act.

2.1.1 WPP president and staff shall support the Board of Directors in overseeing all aspects of the WRAP, including oversight and management of the Program Operator(s) in accordance with any Program Operator agreement(s) entered into by WPP under Section 2.2 of this Tariff.

2.1.2 WPP and its staff shall provide all legal, regulatory, and accounting support for the WRAP, including support for making filings with FERC as authorized by the Board of Directors.

2.1.3 WPP staff shall provide all logistical support necessary to facilitate implementation of the WRAP and specifically all logistical needs of the Board of Directors and reasonable logistical assistance to facilitate meetings and activities of the RAPC, PRC, and all subordinate organizational groups.

2.2 As Program Administrator, WPP shall undertake all actions as necessary to implement and administer the WRAP, including but not limited to engaging one or more Program Operator(s) to perform technical operations of the WRAP including both the Forward Showing Program and Operations Program. Except as otherwise provided herein, WPP may contract for certain activities required by this Tariff to be provided by one or more Program Operator(s) subject to oversight by the Board of Directors, provided, however, that the Program Operator shall operate solely as a contractor under the oversight of WPP, and WPP shall remain the sole point of compliance with this Tariff. WPP shall have the sole authority to enter into contracts for such engagements and is responsible for providing support and compensation for such Program Operator(s) pursuant to any contract(s).

2.2.1 WPP will contract with Program Operator(s) to assist WPP with providing reasonable technical support and expertise to all WRAP organizational groups as governed by the Program Operator’s contract with WPP.

3. Role of the Board of Directors and Limitations on Board Authority

3.1 Authority: Ultimate authority over all aspects of the WRAP as established under this Tariff shall be vested in the independent Board of Directors. Each member of the Board of Directors shall at all times exhibit financial independence from all Participants and classes of Participants, as further provided in the WPP Bylaws and policies. As set forth in Section 2.1 of this Tariff, the Board of Directors shall have the exclusive authority to approve and direct WPP to file amendments to this Tariff with FERC under section 205 of the Federal Power Act, 16 U.S.C. § 824d, subject to the limitations and prohibitions imposed under Section 3.4 of this Tariff. The Board of Directors shall also have the exclusive authority to approve the Business Practice Manuals and any amendments to the Business Practice Manuals, subject to the terms, conditions, and limitations imposed under this Tariff.

3.2 The Board of Directors generally shall meet in open session for all matters related to the WRAP; however, the Board of Directors may meet in closed session as the chair deems necessary to safeguard the confidentiality of sensitive information, including but not limited to discussing matters related to personnel, litigation, or proprietary, confidential, or security sensitive information. The Board of Directors shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session. During open session, the chair of the Board of Directors will reasonably accommodate stakeholder requests to address the Board within the discretion of the chair.

3.3 The Board of Directors shall only consider amendments to this Tariff or the Business Practice Manuals after such amendments are first acted upon by the RAPC, subject to the following additional conditions:

3.3.1 In the event that the RAPC has voted to reject or has not voted to support a proposed amendment to this Tariff or the Business Practice Manuals, any stakeholder may appeal such decision to the Board of Directors, and the Board of Directors shall consider the appeal.

3.3.2 In the event that the RAPC has voted to reject or has not voted to support a proposed amendment to this Tariff or the Business Practice Manuals and a stakeholder has not appealed such decision, the Board of Directors may, on its own motion or motion of any member of the Board of Directors, consider the proposed amendment.

3.3.3 In the event that the COSR as a body opposes or appeals a RAPC decision to the Board of Directors regarding an amendment to this Tariff or the Business Practice Manuals, the process set forth in Section 4.3.3 of this Tariff shall apply prior to the Board of Directors' consideration of the RAPC decision.

3.3.4 In the event that the Board of Directors wishes to initiate an amendment to this Tariff or the Business Practice Manuals that has not undergone PRC

and RAPC review, the Board of Directors shall first submit such proposed amendment to the PRC for review under the processes set forth in Sections 4.1 and 4.2 of this Tariff.

3.3.5 Expedited Review Process: In the event that the RAPC determines that an expedited review process is necessitated by an exigent circumstance as set forth in Section 4.1.3.1.1 of this Tariff, the Board of Directors shall review the RAPC's recommended Tariff or Business Practice Manual amendment expeditiously and invite comment from the PRC, COSR, and stakeholders concurrently with its consideration of the RAPC proposal.

3.4 WPP is specifically prohibited from amending this Tariff to:

3.4.1 Alter, usurp, control, or otherwise materially modify the Participants' existing functional control and responsibility over their generation and transmission assets, including but not limited to planning and operation of such assets, Open Access Transmission Tariff administration, interfering with Balancing Authority duties and responsibilities, or imposing a must-offer requirement on any specific generation resources.

3.4.2 Administer Open Access Transmission Tariff service, engage in Balancing Authority operations, impose transmission planning requirements, or assume any transmission planning responsibilities with regard to any of the Participant's transmission assets.

3.4.3 Form any type of organized market, including but not limited to a capacity market, a regional transmission organization, a real-time market, or any other type of FERC-approved regional construct, unless such action is also approved by the RAPC under its voting procedures set forth in Section 4.1.6 of this Tariff.

3.4.4 Impose any requirements on Participants beyond the assessment of financial charges as specified in this Tariff or suspension or termination of participation for failure to meet any WRAP requirements.

3.4.5 Amend in any way this Section 3 of this Tariff without the approval of the RAPC under its voting procedures set forth in Section 4.1.6 of this Tariff.

3.4.6 Amend the RAPC voting thresholds set forth in Section 4.1.6 of this Tariff.

3.5 Subject to the limitations and prohibitions imposed under Section 3.4 of this Tariff, if the Board of Directors votes to file at FERC to expand the WRAP to include market optimization or transmission planning services, WPP will initiate a formal process with COSR and other stakeholders to conduct a full review of governance structures and procedures, including the role of states. If COSR does not support any revised governance structure that emerges from such WPP review process, the WPP will file, along with any WPP governance proposal to FERC, an alternative

governance structure on behalf of the COSR so long as such COSR alternative governance structure is supported by 75% of the COSR.

4. Organizational Groups for the WRAP

4.1 Resource Adequacy Participants Committee

4.1.1 Authority and Purpose: The RAPC shall be the highest level of authority for representation by Participants in the WRAP governance structure and shall represent the interests of Participants directly to the Board of Directors.

4.1.2 Composition: The RAPC shall be composed of one representative from each Participant. Such representative shall be a senior management official with binding decision-making authority on behalf of the Participant, or a designated representative of a Participant's senior management official. A designated representative shall be required to have binding decision-making authority on behalf of the Participant and shall have all voting rights delegated from the senior management official. Participant shall appoint a designated representative no less than one Business Day in advance of a meeting for that designated representative to be eligible to vote during the meeting.

4.1.3 Functions: The RAPC:

4.1.3.1 Shall consider and recommend that the Board of Directors approve or reject all proposed amendments to this Tariff or Business Practice Manuals prior to the Board of Directors considering such amendments, including any amendments reviewed and referred by the PRC.

4.1.3.1.1 Exigent Circumstances: When the RAPC determines that an amendment to the Tariff or the Business Practice Manuals requires expedited Board of Directors review due to exigent circumstances, it may propose such amendment directly to the Board of Directors without awaiting review by other committees and stakeholders. Exigent circumstances include: (i) a FERC-mandated amendment to this Tariff or the Business Practice Manuals; (ii) an amendment to this Tariff or the Business Practice Manuals to address an immediate reliability impact; or (iii) an amendment to this Tariff or the Business Practice Manuals that the RAPC has determined has significant impacts to utility service.

4.1.3.2 Shall consider and vote to recommend that the Board of Directors approve or reject any proposed amendments to this Tariff or the Business Practice Manuals.

4.1.3.3 May provide input to the Board of Directors on any proposed WPP rules that apply both to the WRAP and other WPP services.

4.1.3.4 May evaluate and provide input to the Board of Directors on the WRAP administration budget and budget allocation to Participants, including amendments to the WRAP Administration Charge as calculated in accordance with Schedule 1 of this Tariff.

4.1.3.5 Shall form and organize all of the organizational groups under its responsibilities.

4.1.3.6 May take other actions reasonably related to its role as the senior-level Participant advisory committee to the Board of Directors regarding WRAP matters.

4.1.4 Leadership: The RAPC shall select from among its members a chair and vice chair.

4.1.5 Meetings:

4.1.5.1 Meetings of the RAPC will generally be open to all stakeholders. WPP shall provide advanced written notice of the date, time, place, and purpose of each RAPC meeting. All RAPC decisional items shall be placed on the open meeting agenda and allotted adequate time for public comment and deliberation.

4.1.5.1.1 The RAPC may meet in closed session as the RAPC chair deems necessary; provided, however, that the RAPC shall allow the designated COSR support staff member as specified in Section 4.3 of this Tariff to attend any closed meeting. The RAPC shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session.

4.1.5.2 The quorum for a meeting of the RAPC or any organizational group organized under it shall be one-half of the representatives thereof, but not less than three representatives, provided that a lesser number may serve as a quorum for the sole purpose of voting to adjourn the meeting to a later time.

4.1.6 Voting:

4.1.6.1 Each RAPC representative shall have one vote.

4.1.6.2 Voting in the RAPC shall utilize a “House and Senate” model.

4.1.6.2.1 Each Participant’s “House” vote shall represent the proportion of the Participant’s Median Monthly P50 Peak Load, as described in Section 2 of Schedule 1 of this Tariff, compared to the sum of all Participants’ Median Monthly P50 Peak Loads. A Participant may choose to divide its

House vote but is responsible for announcing such at the time of voting.

4.1.6.2.2 Each Participant shall receive a single, non-weighted "Senate" vote.

4.1.6.2.3 For an action to be approved by the RAPC, it must pass both "House" and "Senate" votes as follows. For purposes of voting, the percentages identified below specify the percentage threshold of the entire RAPC (whether in attendance or not) that is needed for passage of an action.

4.1.6.2.3.1 Actions to amend any of the limitations on Board authority set forth in Section 3.4 of this Tariff require an 80% affirmative approval by both the House and the Senate vote tallies to be approved.

4.1.6.2.3.2 Actions brought before the RAPC that have been approved by the PRC require a 67% affirmative approval by both the House and Senate vote tallies to be approved.

4.1.6.2.3.3 All other actions not specified in this Section 4.1.6.2.3 require a 75% affirmative approval by both the House and Senate vote tallies to be approved.

4.1.6.2.4 If at any time a single Participant's P50 load for voting purposes would result in that Participant possessing a veto over any votes taken under Section 4.1.5.2.3, such Participant's House vote shall be capped at 1% below the amount that would convey such a veto, such that no single Participant will possess a veto over any action taken under Section 4.1.6.2.3.

4.2 Program Review Committee

4.2.1 Authority and Purpose: The PRC is a sector-representative group comprised in accordance with Section 4.2.2 of this Tariff. The PRC is responsible for receiving, considering, and proposing amendments to this Tariff and the Business Practice Manuals. The PRC shall serve as a clearinghouse of all recommended amendments to this Tariff or the Business Practice Manuals, except for those designated by the RAPC as involving an exigent circumstance under Section 4.1.3.1.1 of this Tariff, amendments to Schedule 1 of this Tariff and cost allocation for the WRAP, and amendments to the WRAPA set forth as Attachment A of this Tariff. The PRC shall serve in an advisory capacity to the RAPC and, when applicable, the Board of Directors.

4.2.1.1 The PRC shall present all proposals received to the RAPC, along with the PRC's recommendation and summaries of all comments and feedback received.

4.2.1.2 The PRC's decisions are advisory-only and are not binding on the RAPC, the Board of Directors, or WPP.

4.2.2 Composition: The PRC shall be composed of up to twenty representatives from the following ten sectors: four representatives of RAPC Participant investor-owned utilities; four representatives of RAPC Participant publicly-owned (consumer or municipal) utilities; two representatives of RAPC Participant retail competition load serving entities; two representatives from RAPC Participant Federal Power Marketing Administrations; two representatives of independent power producers; two representatives of public interest organizations; one representative of retail consumer advocacy groups; one representative of industrial customer advocacy groups; one representative of load serving entities with loads in the WRAP that are represented by other LREs and are not otherwise eligible for any other sector; a representative from the COSR. Expectations for sectors to consider regional, operational, geographic, demographic, and other forms of diversity in selecting their sector representatives are set forth in more detail in the PRC charter, which shall be posted and maintained on the WRAP website or other appropriate public location.

4.2.3 The PRC shall establish a process and criteria for receiving and reviewing proposed amendments to this Tariff and the Business Practice Manuals. Such review will include procedures for stakeholder comment.

4.2.4 Meetings: The PRC shall meet primarily in open session; provided that the PRC may schedule closed meetings if it determines that doing so would be beneficial to safeguard the confidentiality of sensitive information. The PRC shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session.

4.2.5 Voting: The PRC shall endeavor to operate by consensus. When voting is necessary, voting shall consist of one sector one vote, with an affirmative vote of six sectors (as specified in Section 4.2.2 of this Tariff) constituting approval of an action before the PRC.

4.2.5.1 For sectors with four seats, three sector representatives must agree with the action for the sector to be considered an affirmative vote for the action.

4.2.5.2 For sectors with two seats, both sector representatives must agree with the action for the sector to be considered an affirmative vote for the action.

4.2.6 Participants and other entities shall participate in no more than one PRC sector. If a Participant or other entity is eligible to participate in more than one sector, such Participant or other entity shall declare in which sector it will participate.

4.3 Committee of State Representatives

4.3.1. Composition: The COSR is a committee composed of one representative from each state or provincial jurisdiction (either public utility commission or state/provincial energy office) that regulates at least one Participant.

4.3.2 Leadership: The COSR shall determine its leadership, including a chair and vice chair. The chair or vice chair will be requested to attend all open sessions of the RAPC to provide input and advice.

4.3.2.1 The COSR shall designate a COSR support staff member to attend and audit closed meetings of the RAPC under a non-disclosure agreement.

4.3.3 Authority:

4.3.3.1 If the COSR determines that a proposal approved by the RAPC is substantially different from the proposal submitted to the RAPC by the PRC, the COSR may engage in additional public review and comment before the RAPC decision is presented to the Board of Directors; provided that this additional public review and comment does not unreasonably delay presentation to the Board of Directors.

4.3.3.2 If the COSR as a body opposes or appeals a RAPC decision to the Board of Directors, the Board of Directors will not consider the RAPC's decision until the RAPC engages with the COSR to discuss, in at least two public discussions, to attempt to reach a mutually agreeable solution.

4.3.3.2.1 If the appeal relates to an amendment that the RAPC designated as involving an exigent circumstance under Section 4.1.3.1.1 of this Tariff, COSR can require no more than one public discussion, provided that such additional discussion does not unreasonably hinder the timeline for Board of Directors consideration of the proposed amendment.

4.3.4 Voting, Meetings, and Quorum: The COSR may develop its own rules governing voting, meetings, and quorum for action. COSR shall be responsible for its own costs.

5. Independent Evaluator

5.1 WPP shall engage an Independent Evaluator to provide an independent assessment of the performance of the WRAP and any potential beneficial design modifications. The Independent Evaluator shall report directly to the Board of Directors.

5.2 The Independent Evaluator shall conduct an annual review of the WRAP, including but not limited to analyzing prior year program performance, accounting and settlement, and program design.

5.3 The Independent Evaluator shall prepare an annual report of its findings, and any recommended modifications to WRAP design, and present its findings to the WRAP committees and the Board of Directors, subject to any necessary confidentiality considerations. Any data included in the Independent Evaluator's report shall be reported on an aggregated basis as applicable to preserve confidentiality. The Independent Evaluator's annual reports shall be available to the public, except to the extent they contain information designated as confidential under this Tariff, or information designated as confidential by the Independent Evaluator.

5.4 The Independent Evaluator shall not:

5.4.1 Evaluate individual Participants.

5.4.2 Possess any decision-making authority regarding the WRAP or design modifications.

5.4.3 Evaluate WPP's day-to-day operations of the WRAP (except as part of review of prior year program performance).

6. WPP Invoicing and Settlement

6.1 WPP shall be responsible for issuing invoices to, and collecting from, Participants all charges under Schedule 1 of this Tariff for recovery of all WPP costs associated with administering the WRAP.

6.2 WPP shall be responsible for invoicing, collecting, and (as applicable) distributing revenues from Deficiency Charges under Part II of this Tariff and Delivery Failure Charges under Part III of this Tariff.

6.3 Participants are not required to provide credit assurances to WPP to cover charges under Schedule 1 of this Tariff, Deficiency Charges under Part II of this Tariff, or Delivery Failure Charge under Part III of this Tariff.

6.4 Participants shall make full payment of all invoices rendered by WPP for which payment is required to WPP within thirty calendar days following the receipt of the WPP invoice, notwithstanding any disputed amount, but any such payment shall not be deemed a waiver of any right with respect to such dispute. Any Participant that fails to make full and timely payment to WPP of amounts owed upon expiration of the cure period specified in Section 6.4.1 of this Tariff will be in default.

6.4.1 If a Participant fails to make timely payment as required by Section 6.4, WPP shall so notify such Participant. The notified Participant may remedy such asserted breach by paying all amounts due, along with interest on such amounts calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii); provided, however, that any such payment may be subject to a reservation of rights, if any, to refer such matter to dispute resolution procedures under Section 9 of this Tariff. If the Participant has not remedied such asserted breach by 5:00 p.m. Pacific Prevailing Time on the second Business Day following WPP's issuance of a written notice of breach, then the Participant shall be in default.

6.4.2 In the event of a Participant's default under Section 6.4.1 of this Tariff, WPP in its discretion may pursue collection through such actions, legal or otherwise, as it reasonably deems appropriate, including but not limited to the prosecution of legal actions and assertion of claims in the state and federal courts as well as under the United States Bankruptcy Code. After deducting any costs associated with pursuing such claims, any amounts recovered by WPP with respect to defaults for which there was a Default Allocation Assessment shall be distributed to the Participants who have paid their Default Allocation Assessment in proportion to the Default Allocation Assessment paid by each Participant, as calculated pursuant to Section 6.4.3 of this Tariff. In addition to any amounts in default, the defaulting Participant shall be liable to WPP for all reasonable costs incurred in enforcing the defaulting Participant's obligations.

6.4.3 In the event of a Participant's default with respect to an invoice issued by WPP for charges under Schedule 1 of this Tariff, in order to ensure that WPP remains revenue neutral, the Board of Directors may assess against, and collect from, the Participants not in default a Default Allocation Assessment to recover the costs associated with the default. Such assessment shall in no way relieve the defaulting Participant of its obligations.

6.4.3.1 The Default Allocation Assessment shall be equal to:

(20% × (1/N) + (80% × (Participant Median Monthly P50 Peak Load / Sum Participants Median Monthly P50 Peak Load)

where:

N = the total number of Participants, calculated as of the date WPP declares a Participant in default.

Participant Median Monthly P50 Peak Load = for each Participant included in factor "N" above, the Participant's Median Monthly P50 Peak Load as determined in Section 2 of Schedule 1 of this Tariff, recalculated on the day the WPP declares a Participant in default.

All Participants Median Monthly P50 Peak Load = the sum of the Participant Median Monthly P50 Peak Load values for all Participants included in factor "N" above.

7. Credit Requirements and Settlement for Holdback and Delivered Energy

7.1 Credit and Settlement for Holdback and Delivered Energy: Settlement of holdback and delivered energy shall be completed bilaterally between Participants, subject to the following:

7.1.1 Neither WPP nor the Program Operator(s) shall take title to energy or be party to any settlement of holdback or delivered energy.

7.1.2 Participants shall establish credit with each other through one of the following mechanisms. Neither WPP nor the Program Operator(s) shall be involved in the calculation of credit or credit limits.

7.1.2.1 Establish credit directly with each Participant: Participants may establish credit directly with other Participants from whom they may receive delivered energy.

7.1.2.1.1 Such credit should be established in advance of the applicable season.

7.1.2.1.2 The amount of such credit and any credit limit shall be at the discretion of each Participant.

7.1.2.2 WPP shall conduct a competitive solicitation process to identify a third-party service provider to serve as central credit organization and clearing house for credit and settlement. Once such central credit organization is selected, Participants that have not already directly established credit with all other Participants under Section 7.2.2.1 of this Tariff shall establish credit with the central credit organization.

7.1.2.2.1 WPP will provide the central credit organization any Operations Program related information necessary for them to perform their obligations as set forth in the agreement between WPP and the central credit organization.

7.1.2.2.2 All costs associated with the central credit organization service shall be borne by Participants as established in the agreement between WPP and the central credit organization and either billed directly on a transactional basis or else recovered under Schedule 1 of this Tariff.

7.1.2.3 The obligation to arrange sufficient credit shall at all times be on the deficient Participant (i.e., a Participant with a negative sharing calculation in the Operations Program). If a deficient Participant has not made good faith and commercially reasonable efforts to

obtain sufficient credit with a delivering Participant, such delivering Participant shall so notify WPP and shall be excused from any obligation to deliver to such deficient Participant. Nothing in this Section 7 requires a Participant to violate its written risk or credit policy.

7.2 All settlement pricing calculated under this Tariff shall be final and no adjustments to settlement prices shall be allowed after the later of: (1) ninety Days after such settlement prices are posted by WPP; or (2) the final outcome of any dispute resolution process that is initiated by a Participant to dispute a settlement price pursuant to the Dispute Resolution Procedures set forth in Section 9 of this Tariff.

7.2.1 A Participant may invoke the Dispute Resolution Procedures set forth in Section 9 of this Tariff to address calculation errors in any settlement price, but may not invoke the Dispute Resolution Procedures to dispute data sources or to request the use of alternative data sources.

8. Force Majeure, Limitation of Liability, and Indemnification

8.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, pandemic, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither WPP nor the Participant will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff. Notwithstanding the foregoing, the physical inability to perform because of an event of Force Majeure shall not relieve the party of any financial obligations incurred under this Tariff or as a result of the Force Majeure event, unless, and to the extent, such financial obligation is waived or excused under provisions of Part II or Part III of this Tariff expressly providing for such waiver or excuse.

8.2 Limitation of Liability:

8.2.1 Neither WPP nor the Program Operator shall be liable, whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Participant, other entity owning a Qualifying Resource, third party, or other person for any damages whatsoever, including, without limitation, direct, incidental, consequential, punitive, special, exemplary, or indirect damages arising or resulting from any act or omission in any way associated with service provided under this Tariff or any agreement hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of WPP or Program Operator, in which case WPP shall only be liable for direct damages.

8.2.2 Neither WPP nor the Program Operator shall be liable for damages arising out of services provided under this Tariff or any agreement entered into hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency, or imperfection of service, occurring as a result of conditions or circumstances beyond the control of WPP, or resulting from electric system design common to the domestic electric utility industry or electric system operation practices or conditions common to the domestic electric utility industry.

8.2.3 To the extent that a Participant or other person has a claim against WPP, the amount of any judgment or arbitration award on such claim entered in favor of such entity shall be limited to the value of WPP's assets. No party may seek to enforce any claims under this Tariff or any Agreements entered into

hereunder against the directors, managers, members, shareholders, officers, employees, or agents of WPP, or against the Program Operator, who shall have no personal liability for obligations of WPP by reason of their status as directors, managers, members, shareholders, officers, employees, or agents of WPP or by virtue of their status as Program Operator.

8.2.4 To the extent that WPP is required to pay any money damages or compensation or pay amounts due to its indemnification of any other party as it relates to any services provided, acts, or omissions under this Tariff or any agreement entered into hereunder, WPP shall be allowed to recover any such amounts under Schedule 1 of this Tariff as part of the WRAP Administration Charge. Notwithstanding the foregoing, WPP shall be prohibited from recovering under this Tariff any costs associated with any damages, compensation, or indemnification costs that arise: (i) with regard to any acts or omissions that occur outside of this Tariff and any agreements entered into hereunder, or (ii) if a court of competent jurisdiction determines that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of WPP or the Program Operator.

8.2.5 A Participant's liability to another Participant under this Tariff for failure to comply with obligations under this Tariff shall be limited to any charges or payments calculated pursuant to this Tariff; provided, however, that nothing in this Section 8.2.5 shall limit or is intended to foreclose any Participant's liability that may arise under any bilateral agreements between Participants.

8.3 Indemnification: The Participants shall at all times indemnify, defend, and save WPP (and any of its Program Operator(s), agents, consultants, directors, officers, or employees) harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties arising out of or resulting from the performance of activities under this Tariff by WPP, any Program Operator(s), or agents, consultants, directors, officers, or employees of WPP, except in cases of gross negligence or intentional wrongdoing by WPP or the Program Operator. WPP shall credit any proceeds from insurance or otherwise recovered from third parties to Participants who have paid to indemnify WPP under this Section 8.3.

8.4 Actions upon Unavailability of Program Operator(s): In the event that the Program Operator(s) become(s) unwilling, unable, or otherwise unavailable to perform contractual duties necessary for WPP to discharge its obligations under this Tariff and WPP’s agreement(s) with the Program Operator(s), WPP shall engage with Participants as soon as practicable to determine what actions to take, including but not limited to filing with FERC a request to waive one or more provisions of this Tariff up to and including immediate suspension of all rights and obligations under this Tariff until a replacement Program Operator(s) can assume all relevant Program Operator functions.

9. Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Subject to the limitations set forth in Section 7.2.1 of this Tariff, any dispute between a Participant and WPP under the Tariff (excluding amendments to the Tariff or to any agreement entered into under the Tariff, which shall be presented directly to the FERC for resolution) shall be referred to a designated senior representative of WPP and a senior representative of the Participant for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty days (or such other period as the parties may agree upon) by mutual agreement, such dispute shall then be referred to the chief executive officer or comparable executive of each party for resolution. In the event that the executives are unable to resolve the dispute within thirty days (or such other period as the parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

9.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the parties to the dispute. If the parties fail to agree upon a single arbitrator within ten days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable FERC regulations.

9.3 Arbitration Decisions: Unless otherwise agreed by the parties, the arbitrator(s) shall render a decision within ninety days of appointment and shall notify the parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and/or any agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the FERC if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (i) the cost of the arbitrator chosen by the party to sit on the three-member panel and one half of the

cost of the third arbitrator chosen; or (ii) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under the Federal Power Act: Nothing in this section shall restrict the rights of any person to file a complaint with the FERC under relevant provisions of the Federal Power Act or of WPP to file amendments to this Tariff under the relevant provisions of the Federal Power Act.

10. Treatment of Confidential and Commercially Sensitive Information of Participants

10.1 Terms: For purposes of this Section 10 only, the term "WPP" shall also include, as applicable, any directors, officers, employees, agents, or consultants of WPP, the Independent Evaluator established under Section 5 of this Tariff, and any central credit organization established under Section 7 of this Tariff. WPP shall be bound by the rights, obligations, and conditions set forth in this Section 10. For purposes of this Section 10, the term "Disclosing Entity" shall include any Participant that discloses information to WPP that the Disclosing Entity deems and identifies as confidential or commercially sensitive. WPP's collection and handling of non-Participant data shall be governed by separate non-disclosure agreements with such non-Participants.

10.2 Treatment of Confidential or Commercially Sensitive Information: WPP shall identify in the Business Practice Manuals categories of Participant-specific data and information received from Participants that shall be treated as confidential or commercially-sensitive, which WPP shall not disclose publicly or to any other Participant or other entity except as provided for in this Section 10. In addition, WPP shall maintain the confidentiality of all of the documents, data, and information provided to it by any Participant that such disclosing Participant deems and specifically identifies as confidential or commercially sensitive. Notwithstanding the foregoing, WPP need not keep confidential: (i) information that is publicly available or otherwise in the public domain; or (ii) information that is required to be disclosed under this Tariff or any applicable legal or regulatory requirement (subject to the procedures set forth in Section 10.4 of this Tariff).

10.2.1 WPP staff may develop and release publicly composite or aggregated data based upon Participant confidential or commercially sensitive information, provided that such composite or aggregated data cannot be used to identify or attribute a disclosing Participant's confidential or commercially sensitive data. Such release of composite or aggregated data shall be governed by the following process.

10.2.1.1 Prior to the initial release of such composite or aggregated data, WPP staff shall present the form and format of such data to each Participant whose confidential information or data will be used to create the composite or aggregated data. If any such Participant objects to the form and format as revealing or allowing for attribution of confidential or commercially sensitive Participant-specific data, WPP staff shall determine whether to modify the form and format or to retain the proposed form and format for release. If WPP staff elects to retain the proposed form and format, the Participant shall have the right to appeal to the RAPC and WPP staff shall be prohibited from releasing the composite or aggregated data in the proposed form and format until the Participant's appeal rights as specified in this Section 10.2.1

are exhausted.

10.2.1.2 If a Participant appeals a WPP staff decision regarding the form and format of composite or aggregated data to the RAPC, the RAPC shall consider whether the form and format reveals or allows for attribution of confidential or commercially sensitive Participant-specific data. If the RAPC determines that the proposed form and format is sufficient to protect against the release of confidential or commercially sensitive Participant-specific data, WPP staff is authorized to release the composite or aggregated data in the proposed form and format unless the Participant timely appeals the RAPC decision to the Board of Directors.

10.2.1.3 If a Participant appeals a RAPC decision regarding the form and format of composite or aggregated data to the Board of Directors, the Board of Directors shall consider whether the form and format is sufficient to protect against the release or attribution of confidential or commercially sensitive Participant-specific data. If the Board of Directors determines that the proposed form and format is sufficient to protect against the release of confidential or commercially sensitive Participant-specific data, WPP staff is authorized to release the composite or aggregated data in the proposed form and format.

10.2.1.4 Once a proposed form and format of composite or aggregated data is approved by the WPP staff and is not appealed or appeals are unsuccessful, such form and format may be used for all future disclosures of composite or aggregate information and no Participant may dispute such release. If WPP staff proposes to alter the form and format, including but not limited to changing the granularity of data, WPP staff shall be required to follow the process set forth in this Section 10.2.1 and Participants shall have the right to appeal such changes in form and format as set forth herein. Notwithstanding the foregoing, if the composition of Participants in the WRAP changes in such a way that the form and format of composite or aggregated data is no longer sufficient to protect against disclosure or attribution of confidential or commercially sensitive Participant-specific data, an aggrieved Participant shall have a one-time right to raise the issue promptly with WPP Staff for presentation to and review by the Board of Directors, and the Board of Directors in its sole discretion shall decide whether the change in composition results in the form and format of the composite or aggregated data becoming insufficient to

protect against the release or attribution of confidential or commercially sensitive Participant-specific data; provided, however, that if an aggrieved Participant does not raise its concerns with the Board of Directors promptly following the change in composition, such Participant shall have waived its right to contest the release of such composite or aggregated data.

10.2.2 Notwithstanding anything to the contrary in this Section 10.2, if the RAPC unanimously votes to disclose publicly any particular category of Participant-specific data, such data shall no longer be deemed confidential regardless of any such designation by a disclosing Participant, and this election shall be binding on any current and future Participants until such time as the RAPC votes unanimously to prohibit public release of such category of data. A list of the categories of Participant-specific data that the RAPC unanimously votes to make public shall be included in the Business Practice Manuals.

10.3 Access to Confidential or Commercially Sensitive Information: Except as otherwise provided in Section 10.2 of this Tariff, no Participant, entity owning a Qualifying Resource, or any third party shall have the right hereunder to receive from WPP or to otherwise obtain access to any documents, data or other information that has been identified as or deemed to be confidential or commercially sensitive under Section 10.2 of this Tariff by a disclosing Participant. The provisions of this Section 10.3 do not apply to WPP (including any Independent Evaluator, member of the Board of Directors, or any WPP officer, employee, agent, or consultant that requires access to confidential or commercially sensitive information); provided that access to Participant-specific confidential or commercially sensitive information shall be solely for the purpose of performing the duties or functions under this Tariff or otherwise advising or assisting WPP. WPP shall develop internal policies and controls governing the handling and protection of confidential or commercially sensitive Participant-specific data by members of the Board of Directors, officers, employees, agents, consultants, or any Independent Evaluator.

10.4 Exceptions: Notwithstanding anything in this Section 10 to the contrary:

10.4.1 If WPP is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 10, WPP may disclose such information; provided, however, that as soon as practicable after WPP learns of the disclosure requirement and prior to making such disclosure, WPP shall notify any affected disclosing Participant of the requirement and the terms thereof. Any such disclosing Participant may, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement and WPP shall cooperate with such disclosing Participant to take all reasonable available steps to oppose

or otherwise minimize the disclosure of the information permitted by applicable legal and regulatory requirements. WPP shall further cooperate with such disclosing Participant to the extent reasonably practicable to obtain proprietary or confidential treatment of confidential or commercially sensitive information by the person to whom such information is disclosed prior to any such compelled disclosure.

10.4.2 WPP may disclose confidential or commercially sensitive information, without notice to any affected disclosing Participant(s), in the event that FERC, during the course of an investigation or otherwise, requests information that is confidential or commercially sensitive. In providing the information to FERC, WPP shall take action, consistent with 18 C.F.R. §§ 1b.20 and/or 388.112, to request that the information be treated by FERC as confidential and non-public and, if appropriate, as Critical Energy Infrastructure Information and that the information be withheld from public disclosure. WPP shall provide the requested information to FERC within the time provided for in the request for information. WPP shall notify any affected disclosing Participant(s) within a reasonable time after WPP is notified by FERC that a request for disclosure of, or decision to disclose, the confidential or commercially sensitive information has been received, at which time WPP and any affected disclosing Participant may respond before such information would be made public.

10.5 Notwithstanding any efforts undertaken pursuant to Section 10.4 to prevent or limit the release of a Participant's confidential or commercially sensitive information, in the event that FERC or a court of competent jurisdiction orders or otherwise permits the public release of a Participant's confidential or commercially sensitive information, the affected Participant shall have a one-time right to elect to terminate its participation in the WRAP under the expedited termination provisions set out in Section 11.2 of the WRAPA.

10.6 WPP shall handle any information identified or deemed to be Controlled Unclassified Information/Critical Energy Infrastructure Information in accordance with FERC's regulations set forth at 18 C.F.R. § 388.113 and any applicable FERC policies or other regulations, including but not limited to restricting access to such information on a password-protected portion of WPP's website or similar precautions.

10.7 Nothing in this Section 10 is intended to limit a Participant's ability to disclose or release publicly its own confidential or commercially sensitive information or data, or to limit a Participant's ability to authorize WPP's disclosure of such material to a specified recipient.

11. Timing

11.1 In the event that any deadline specified in this Tariff shall fall on a day that is not a Business Day, the deadline shall be extended to the next Business Day.

12. Application and Registration

12.1 Any entity wishing to participate in the WRAP must submit an application and registration in accordance with the Business Practices Manuals and must execute the WRAPA as set forth in Attachment A of this Tariff, or a non-conforming version of such participation agreement that is approved by FERC for an individual Participant. Such application and registration must be submitted in accordance with the timelines set forth in the Business Practices Manuals in advance of the next Binding Season.

12.2 Each Participant must register all of its resources and loads, regardless of whether such resources will be used to satisfy the WRAP requirements and regardless of whether certain loads will be subject to the requirements of the WRAP. Participants may modify their registration of resources and loads in accordance with the timing procedures set forth in the Business Practices Manuals.

12.3 In the event that more than one Participant attempts to register the same resource or load, the following procedure will be used to assign the resource or load to a Participant:

12.3.1 If a Participant attempts to register a load or resource that has already been registered by a different Participant, the resource or load will remain registered by the original Participant registering the resource or load until such time as both Participants mutually inform WPP that a change to the registration is required.

12.3.2 If two or more Participants attempt to register the same resource or load during the same registration window, WPP shall request that the Participants determine among themselves the appropriate registration of the resource or load before that resource or load is included in the WRAP.

PART II FORWARD SHOWING PROGRAM

13. Overview

13.1 In the Forward Showing Program, as set forth in this Part II of the Tariff, and as further detailed in the Business Practice Manuals, each Participant shall, in advance of each Binding Season, show as to such Binding Season: (i) the total capacity, referred to and defined herein as the FS Capacity Requirement, required by the provisions of this Tariff for such Binding Season for reliable service to the loads for which such Participant is responsible; (ii) the demonstration of capacity, referred to and defined herein as the Qualifying Capacity Contribution, or QCC, provided by the Qualifying Resources the Participant provides or procures to meet its FS Capacity Requirement; and (iii) at least the minimum level of firm transmission service, referred to and defined herein as the FS Transmission Requirement, needed for reliable delivery of the QCC of the Participant's Qualifying Resources from such resources to the loads for which the Participant is responsible.

13.2 As also set forth in this Part II of the Tariff, and as further detailed in the Business Practice Manuals: (i) WPP shall, in advance of each Binding Season, review the Forward Showing Submittals of each Participant for such Binding Season; (ii) WPP shall identify to the Participant any deficiencies in the Participant's Portfolio QCC (whether as to contracts or directly owned or controlled resources) relative to the FS Capacity Requirement, and any deficiencies in the identified firm transmission service relative to the FS Transmission Requirement, within sixty days of the Forward Showing Submittal deadline; (iii) the Participant shall have an opportunity to cure such deficiencies, within sixty days of notification of deficiency; and (iv) if the Participant fails to cure all such deficiencies on or before the deadlines prescribed herein, the Participant shall be assessed a Forward Showing Deficiency Charge.

14. Forward Showing Program Process and Timeline

14.1 The Forward Showing Program has two Binding Seasons, defined as the Summer Season and the Winter Season. The Summer Season is the period beginning on June 1 of each Year and ending on September 15 of that same Year. The Winter Season is the period beginning on November 1 of each Year and ending on March 15 of the succeeding Year. This Tariff does not establish resource or showing obligations outside the periods defined by the Summer Season and Winter Season.

14.2 Each Participant shall submit its Forward Showing Submittals for each Month of each Binding Season, with all required supporting materials and information as detailed in the Business Practice Manuals, on or before the FS Deadline for the Binding Season. The FS Deadline for each Binding Season shall be seven months before the start of such Binding Season.

14.2.1 Forward Showing Submittal:

14.2.1.1 Absent the exception in Section 14.2.1.2, each Participant shall submit a separate Forward Showing Submittal for loads for which it is responsible if transmission constraints between areas where its loads are located, including, without limitation, when Participant is responsible for loads in more than one Subregion, prevent application, in the manner more fully described in the Business Practice Manuals, of Resource QCC or Net Contract QCC from one load area to the FS Capacity Requirement of another load area.

14.2.1.2 Notwithstanding Section 14.2.1.1, a Participant responsible for loads in two Subregions may submit for a given Month a single Forward Showing Submittal for such loads, and may employ for determination of its FS Capacity Requirement for such Month the lower of the two FSPRM values determined for the Subregions where its loads are located, if the Participant demonstrates in such Forward Showing Submittal, in accordance with the procedures and requirements set forth in the Business Practice Manuals, transmission service rights of the type required by the FS Transmission Requirement, in a quantity, in addition to that required by the FS Transmission Requirement, equal to the difference in the two FSPRM values multiplied by the Participant's P50 Peak Load Forecast for such Month, with a point of delivery in the Subregion with the higher FSPRM value and the point of receipt in the Subregion with the lower FSPRM value. Each such showing shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service.

14.2.2 Each Participant's Forward Showing Submittal shall include a Senior Official Attestation.

14.3 The FSPRM values used in the Forward Showing Submittals for a Binding Season shall be those values approved by the Board of Directors as the culmination of an Advance Assessment process. No later than twelve months before the FS Deadline for each Binding Season, WPP will determine and post the recommended FSPRM for each Subregion for each Month of such Binding Season. Participants shall provide their load, resource and other information reasonably required to perform the analyses and calculations required for the Advance Assessment, in accordance with the Advance Assessment information submission details and schedule specified in the Business Practice Manuals. No later than nine months before the FS Deadline for such Binding Season, the Board of Directors shall take its final action regarding approval of the FSPRM values for each Month of such Binding Season.

14.3.1 In connection with an Advance Assessment process, or otherwise in connection with consideration of a change to the Business Practice Manuals, the Board of Directors may determine that designation of Subregions would encourage the relief, in whole or part, of transmission constraints on the transfer of capacity within the WRAP Region (whether through development or commitment of transmission, of Qualifying Resources, or by other means) to the benefit of the WRAP Region and the advancement of the objectives of the WRAP. Each such Subregion shall be identified in the Business Practice Manuals.

14.3.2 Any Participant may choose to offer in the Advance Assessment process transmission service rights owned or controlled by such Participant for firm delivery of capacity from one Subregion to another Subregion, for use by other Participants under the terms of Part III of this Tariff during any or all identified Months of the applicable Binding Season. Each such offer shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service. No Participant is obligated to offer any such transmission service rights in the Advance Assessment process, but any offer so made and not withdrawn before the deadline during the Advance Assessment process specified in the Business Practice Manuals shall be considered a binding offer of the identified transmission service rights which may not be withdrawn before the end of the last Day of the Month for which such transmission service is offered. WPP shall take account of such offered transmission service rights, along with other transmission deliverability reasonably anticipated to be available for use by Participants for WRAP purposes during the applicable Binding Season in its determination of the recommended FSPRM values for each Month of the

applicable Binding Season for the WRAP Region and for each affected Subregion.

14.4 No later than sixty Days after the FS Deadline for a Binding Season, WPP will (i) provide the values of the Participant's FS Capacity Requirement and FS Transmission Requirement for each Month of the Binding Season; (ii) affirm that the Portfolio QCC of such Participant for each Month of the Binding Season equals or exceeds the FS Capacity Requirement of such Month for such Participant or notify such Participants of any deficiencies in the Forward Showing Submittal that result in a failure to demonstrate satisfaction of the FS Capacity Requirement; and (iii) affirm that the Demonstrated FS Transmission plus approved Monthly Transmission Exceptions of such Participant for each Month of the Binding Season equals or exceeds the FS Transmission Requirement of such Month for such Participant or notify such Participants of any deficiencies in the Forward Showing Submittal that result in a failure to demonstrate satisfaction of the FS Transmission Requirement.

14.5 Within 120 Days after the FS Deadline, the Participant shall (i) submit revisions to its Forward Showing Submittal, including, without limitation, additions or revisions to the Participant's Resource QCC, Net Contract QCC, or Demonstrated FS Transmission; (ii) in order to fully cure all identified deficiencies and demonstrate that such Participant's Portfolio QCC for each Month of the Binding Season equals or exceeds its FS Capacity Requirement; and (iii) fully provide Demonstrated FS Transmission for each Month of the Binding Season that equals or exceeds its FS Transmission Requirement for the same Month of the Binding Season where WPP identified deficiencies.

14.5.1 Any Participant that fails to cure identified deficiencies in its Forward Showing Submittal within the period prescribed above shall be assessed a Deficiency Charge.

15. Transition Period

15.1 Except as specified in Section 15.1.1, the Binding Season beginning November 1, 2027, will be the first Binding Season for which all Participants will assume the obligations of demonstrating capacity and making surplus capacity available to other Participants and will receive the benefits of reliance upon other Participants' surplus capacity. Any Binding Season during the Transition Period occurring before November 1, 2027, shall be a Non-Binding Season, as specified in Section 15A of this Tariff.

15.1.1 No later than January 15, 2026, a Participant may elect the Binding Season beginning June 1, 2027, as the first Binding Season for which it will assume the obligations of demonstrating capacity and making surplus capacity available to other Participants and will receive the benefits of reliance upon other Participants' surplus capacity by providing written notice of its election.

15.2 Within two years prior to the start of the first Binding Season of the WRAP, a Participant who has elected to participate in the first Binding Season may request a vote of all Participants who have elected to participate in the first Binding Season to delay implementation of the first Binding Season for up to two Seasons. Delayed implementation of the first Binding Season shall be approved if 75% of the Participants who elected to participate in the first Binding Season vote in favor of such delay, with approval requiring a vote of 75% of both the House and Senate vote tallies (as described in Sections 4.1.6.2.1 and 4.1.6.2.2 of this Tariff) of all Participants who elected to participate in the first Binding Season.

15.2.1 The deferral vote may only occur for the first Binding Season of the WRAP. If the Participants who elected to participate in the first Binding Season of the WRAP vote to delay implementation of the first Binding Season, all compliance charges for the Forward Showing Program and Operations Program are automatically deferred; except that the Participants may vote to delay implementation only of the Operations Program portion of the first Binding Season and retain the binding Forward Showing Program portion of the first Binding Season.

15A. Non-Binding Seasons

15A.1 A Participant will participate as a Non-Binding Participant for certain Binding Seasons in the Transition Period, as detailed in Section 15.1 of this Tariff, and when Critical Mass is not achieved for a given Binding Season, as detailed in Section 15A.2 of this Tariff. As to a Non-Binding Season, the Participant:

15A.1.1 Shall not be subject to Deficiency Charges, Transmission Deficiency Charges, Holdback Requirements, Energy Deployment obligations, or Delivery Failure Charges;

15A.1.2 Shall submit Forward Showing Submittals but shall not be required to cure deficiencies;

15A.1.3 Shall not have a mandatory Holdback Requirement as a result of the Sharing Calculation;

15A.1.4 May only receive Holdback Capacity offered voluntarily by other Participants in accordance with Part III of this Tariff; and

15A.1.5 Shall have all rights and be subject to all obligations under Part I of this Tariff and the Participant's WRAPA, including, without limitation, voting rights, committee participation, and the obligation to pay the WRAP Administration Charge.

15A.2 Once WPP has given notice to Participants that their Subregion does not have Critical Mass for a given Binding Season, each such Participant will have 30 days to provide notice to WPP if it intends to participate as a Non-Binding Participant for that Binding Season. Such notice and election will be given similarly for each season without Critical Mass participation.

16. Components of the Forward Showing

16.1 FS Capacity Requirement. The FS Capacity Requirement shall be determined for each Participant on a monthly basis by applying the applicable Monthly FSPRM for a Month to such Participant's peak load forecast for that Month. The Participant's peak load forecast for a given Month of a Binding Season will be the P50 Peak Load Forecast for the Binding Season multiplied by a shaping factor based on the historical relationship, for such Participant, of the seasonal peak for the Winter Season or Summer Season, as applicable, and the monthly peaks for the Months in such season, as more fully described in the Business Practice Manuals.

16.1.1 P50 Peak Load Forecast. The P50 Peak Load Forecast is a peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast. The Business Practice Manuals shall specify an approved load forecasting methodology for use by all Participants for their WRAP-required load forecasts which shall include (i) a base monthly peak derived from a recent historical period that recognizes additions and removals of load during the historical period, (ii) adjustments for known additions and removals of load during the forecast window; and (iii) a specified load growth factor.

16.1.2 FS Planning Reserve Margin

16.1.2.1 The FSPRM is an increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, expressed as a percentage of the applicable peak load forecast. The FSPRM shall be determined based on probabilistic analysis, taking account of uncertainties in generation and load, as the margin above peak load that provides an expectation of no more than a single event-day of loss of load in ten years (sometimes referred to herein as the "1-in-10 LOLE") for each Binding Season. The FSPRM shall be determined in a manner that accounts for the governing principles of QCC value determinations set forth in Section 16.2.5 of this Tariff and shall employ the applicable peak load for the applicable Binding Season and Months. Additional details, assumptions, methodologies, and procedures for determination of the FSPRM shall be as set forth in the Business Practice Manuals.

16.1.2.2 WPP shall calculate in the Advance Assessment process the recommended Monthly FSPRM for each Month of each Binding Season, for approval by the Board of Directors as set forth in this Part II.

16.1.2.3 The FSPRM shall employ (i) a simulated resource stack using capacity accreditation principles consistent with those used for WRAP QCC determinations; (ii) an adjustment in the total WRAP-required QCC value as needed to meet a 1-in-10 LOLE for each Binding Season, and (iii) while maintaining the 1-in-10 LOLE for each Binding Season in (ii), include a monthly reduction of capacity to ensure that each Month has at least 0.01 annual LOLE. The FSPRM for a Month shall be the simulated QCC as adjusted to meet the 1-in-10 LOLE for each Binding Season minus the P50 Peak Load Forecast for the Month, divided by the P50 Peak Load Forecast for the Month.

16.1.2.4 The FSPRM shall include an approximation of Contingency Reserves as set forth in the Business Practice Manuals.

16.1.3 Contingency Reserves Adjustment. A Participant's FS Capacity Requirement will be adjusted as set forth in the Business Practice Manuals to account for changes in Contingency Reserve requirements resulting from energy contract purchases and contract sales.

16.1.4 A Participant responsible for loads located in a Subregion for which an FSPRM value has been determined that is higher than the FSPRM value determined for a different Subregion may, in lieu of demonstrating a MW increment of Portfolio QCC otherwise required to satisfy such Participant's FS Capacity Requirement for a given Month, demonstrate in its Forward Showing Submittal, in accordance with the procedures and requirements set forth in the Business Practice Manuals, transmission service rights of the type required by the FS Transmission Requirement, in a quantity, in addition to that required by the FS Transmission Requirement, that is no greater than the difference in the two FSPRM values multiplied by the Participant's P50 Peak Load Forecast, with the point of delivery in the Subregion with the higher FSPRM value and the point of receipt in the Subregion with the lower FSPRM value. The MW quantity of the additional transmission so demonstrated shall reduce for such Month, by the same MW quantity, the Portfolio QCC the Participant would otherwise be required to demonstrate to satisfy its FS Capacity Requirement for such Month. Each such demonstration shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service.

16.2 Qualified Capacity Contribution

16.2.1 For each Participant and each Binding Season, the Forward Showing shall show and support the Portfolio QCC, which shall be the sum of the QCC of the Participant's Qualifying Resources ("Resource QCC"), the QCC of its

contracted capacity ("Net Contract QCC"), and any transfers of capacity already accredited by another Participant ("Total RA Transfer," which could be positive or negative). The Portfolio QCC effective for a Binding Season shall be the value determined by WPP.

16.2.2 A resource will not be assigned a Resource QCC or counted toward Portfolio QCC unless it is a Qualifying Resource. Qualifying Resources are those that, before they are included in a Forward Showing Submittal, are first registered with WPP. A Participant seeking registration of a resource must submit a request for registration providing the resource information described in the Business Practice Manuals.

16.2.3 The minimum resource size for registration of a resource is 1 MW, provided, however, that Participants with responsibility for individual resources of less than 1 MW may aggregate them to meet the 1 MW minimum requirement, under the conditions and limitations specified in the Business Practice Manuals.

16.2.4 A Participant may include in its Forward Showing Submittal a request for an exception from its FS Capacity Requirement for an insufficiency of its Portfolio QCC solely due to (i) a catastrophic failure of one or more Qualifying Resources due to an event of Force Majeure as defined by Section 8.1 of this Tariff that (ii) the Participant is unable to replace on commercially reasonable terms prior to the FS Deadline as a result of the timing and magnitude of such catastrophic failure and its consequences. As more fully set forth in the Business Practice Manuals, such exception request shall be supported by a Senior Official Attestation. The exception request must include complete information on the nature, causes and consequences of the catastrophic failure, and must describe the Participant's specific, concrete efforts prior to the FS Deadline to secure replacement Qualifying Resources for the applicable Binding Season. WPP will consider the exception criteria established by this section, the information provided in the exception request, the completeness of the exception request, and other relevant data and information, in determining whether to grant or deny an FS Capacity Requirement exception request. WPP shall provide such determination no later than sixty days after submission of such Participant's FS Submittal containing such FS Capacity Requirement exception request. A Participant granted an exception hereunder must complete a monthly exception check report demonstrating that either the circumstances necessitating the exception have not changed; or that Qualifying Resources have become available, and the Participant has acquired them and no longer requires the exception. Failure to timely submit a required monthly report will result in assessment of a Deficiency Charge, unless the deficiency is cured within seven days of notice of non-compliance. A Participant denied an exception request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In

such event, the requested exception shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall give notice of any exception granted hereunder in the time and manner provided by the Business Practice Manuals.

16.2.5 QCC: WPP shall determine QCC values for the resource types specified below in accordance with the governing principles specified below for each resource type, and consistent with further details specified for each resource type in the Business Practice Manuals.

16.2.5.1 For resources that use conventional thermal fuels, including but not limited to, coal, natural gas, nuclear, and biofuel, WPP will determine QCC based on an Unforced Capacity methodology that employs resource-specific capability testing and capability requirements to determine an Installed Capacity value, and a forced outage calculation methodology based on historical performance during Capacity Critical Hours over a specified multi-year period (excluding outages properly reported as "outside management control"), or based on class-average forced outage data, as specified in the Business Practice Manuals, if there is insufficient data on historical performance.

16.2.5.2 For resources that are Variable Energy Resources, including, but not limited to, wind and solar resources, WPP will determine QCC based on an ELCC methodology, that accounts for synergistic portfolio effects within and among VER types at different resource penetration levels that influence the extent to which the WRAP Region can rely on those VER categories to meet overall capacity needs.

16.2.5.2.1 For such purpose, a separate ELCC value will be calculated in the aggregate for all VER resources of a given type in an identified VER Zone, to be delineated in the Business Practice Manuals based on factors such as geography, performance, meteorological considerations, and penetration.

16.2.5.2.2 As more fully described in the Business Practice Manuals, the zonal aggregate VER-resource-type value will be calculated by (i) conducting a benchmark LOLE study that includes all resource types except the VER resource type being studied, employing a model and assumptions consistent with those used to calculate FSPRM, and adding, or subtracting, the same MW quantity of Pure Capacity to every hour of the applicable Binding Season until,

respectively, an initial LOLE value above 0.1 day per Binding Season becomes 0.1 day per Binding Season, or an initial LOLE value below 0.1 day per Binding Season becomes 0.1 day per Binding Season; (ii) conducting an LOLE study that includes all resource types including the VER resource type being studied, employing a model and assumptions consistent with those used to calculate FSPRM, and adding, or subtracting, the same MW quantity of Pure Capacity to every hour of the applicable Binding Season until, respectively, an initial LOLE value above 0.1 day per Binding Season becomes 0.1 day per Binding Season, or an initial LOLE value below 0.1 day per Binding Season becomes 0.1 day per Binding Season; and (iii) subtracting the Pure Capacity value determined under subpart (ii) from the Pure Capacity value determined under subpart (i) (for which calculation a Pure Capacity value subtracted from each hour in either subpart (i) or subpart (ii) will be assigned a negative value; (iv) repeating steps (i) through (iii) for each Binding Season of the study period employing historical, or as necessary, synthesized, data; and (v) basing the aggregate value of the studied VER resource type for the studied VER Zone on the results of the calculation in step (iii) for the Binding Seasons studied, which may include differential weighting of the Binding Seasons studied as appropriate to improve the quality and predictive capacity of the final result.

16.2.5.2.3 The aggregate capacity calculated for each VER resource type in each VER Zone will then be allocated to VERs of that type in that VER Zone based on each such resource's average historical performance if at least three years of historical performance or three years of synthesized forecast data during the WRAP Region's CCH is available at the time of such allocation. If three years historical performance or synthesized forecast data is not then available, the average ELCC from the VER Zone will be assigned.

16.2.5.3 For resources that are Energy Storage Resources, WPP will determine QCC based on an ELCC methodology comparable to that used for VERs. The ELCC methodology will model Energy Storage Resources at the level of their usable capacity that can

be sustained for a minimum duration of four hours. An Energy Storage Resource need not have a nameplate rating that assumes a minimum of four hours in order to receive a QCC determination, but the QCC in that case will be scaled to reflect the capability that can be sustained for four hours, as more fully described in the Business Practice Manuals.

16.2.5.4 A Participant's Demand Response used as a Demand Response Capacity Resource must be controllable and dispatchable by the Participant or by the host utility, and must have met certain testing requirements consistent with Business Practice Manuals. WPP will determine Demand Response Load Modifier QCC by multiplying the load reduction in MWs by the number of hours the resource can demonstrate load reduction capability (for a period of up to five continuous hours) divided by five. The effects of Demand Response used as a Demand Response Capacity Resource must not be included in load provided for a Participant's Advance Assessment.

16.2.5.5 For Storage Hydro Qualifying Resources, the Participant will calculate a QCC based on a methodology detailed in the Business Practice Manuals that: (i) considers each resource's actual generation output, residual generating capability, water in storage, reservoir levels, and flow or project constraints over the previous ten-year historical period; (ii) determines the project's QCC by assessing the historical generation during CCHs on any given day and ability to increase generation during CCHs on the same day, subject to useable water in storage, inflows/outflows, and expected project operating parameters/constraints and limitations; (iii) incorporates forced outage rates; and (iv) determines QCC as average contribution to the CCH for each Winter Season and Summer Season over the previous ten years. If ten years of historical data is not available for the Storage Hydro Qualifying Resource, the Participant may alternatively employ data on the same metrics from a demonstrably comparable facility or apply another method that provides reasonable confidence in the reliability of the predicted values, as more fully set forth in the Business Practice Manuals. The Participant's QCC calculation shall be subject to review and validation by WPP. In connection with such review, the Participant shall provide WPP with the following information necessary to calculate a QCC for Storage Hydro Qualifying Resources: (i.a) historical reservoir elevation levels; (ii.a) historical plant generation; (iii.a) elevation versus capacity curves; (iv.a) any minimum or maximum reservoir level constraints; (v.a) forced outage rates; (vi.a) volume of water

versus reservoir elevation storage tables; and (vii.a) turbine discharge versus generation efficiency curve.

16.2.5.6 For Run of River Qualifying Resources, WPP will determine QCC based on the monthly average performance of such resource during Capacity Critical Hours, as further specified in the Business Practice Manuals

16.2.5.7 For resources that (i) are not within the meaning of any of Sections 16.2.5.1 through 16.2.5.5, and that (ii) either (a) are not dispatchable; or (b) require the purchaser of energy from the resource to take energy as available from such resource, including but not limited to a qualifying facility as defined under the Public Utility Regulatory Policies Act of 1978, WPP will determine QCC based on the monthly average performance of such resource during Capacity Critical Hours, as further specified in the Business Practice Manuals.

16.2.6 Net Contract QCC: WPP shall determine Net Contract QCC for the agreement types specified below in accordance with the governing principles specified below for each agreement type, and consistent with further details specified for each agreement type in the Business Practice Manuals. Net Contract QCC may be either positive or negative, to take account of, for example, a Participant's agreements for the sale of capacity to any other party.

16.2.6.1 Absent one of the exceptions described and limited below, capacity supply agreements qualifying for a Net Contract QCC in the WRAP must be resource specific, and therefore must include, among other requirements, an identified source, an assurance that the capacity is not used for another entity's resource adequacy requirements, an assurance that the seller will not fail to deliver in order to meet other supply obligations, and affirmation of NERC Priority 6 or 7 firm point-to-point transmission service rights or network integration transmission service rights from the identified resource to the point of delivery/load. The specific resources identified in a capacity supply agreement qualifying for Net Contract QCC shall meet the same Resource QCC accreditation requirements for the given resource type, as specified in Section 16.2.5.

16.2.6.2 A system sales contract can qualify for a Net Contract QCC value, provided that if the seller is not a Participant, the system capacity that is the subject of the agreement must be deemed surplus to the seller's estimated needs, there must be an assurance that the seller will not fail to deliver in order to meet other commercial obligations, and there must be NERC Priority

6 or 7 firm point-to-point transmission service rights or network integration transmission service rights from the identified resource to the point of delivery/load. Surplus status may be demonstrated by a Senior Official Attestation with pertinent supporting details for such surplus status, including written assent of the non-Participant Seller, secured by the purchasing Participant. Such attestation is not required if the seller is a Participant, because the information needed to verify surplus status is already available.

16.2.6.3 A supply agreement entered into prior to October 1, 2021 ("Legacy Agreement") can qualify for a Net Contract QCC value; provided that where a legacy agreement does not identify the source, it must be possible for WPP to presume a source or sources for the contract, including with the written assent of the supplier under such Legacy Agreement, conveyed in the form and manner set forth in the Business Practice Manuals. A Legacy Agreement for which such resource determination cannot be reasonably made will not be counted as adding to the Portfolio QCC.

16.2.7 Total RA Transfer: A Participant may agree with another Participant on a transfer of a portion of its Portfolio QCC to meet the other's FS Capacity Requirement ("RA Transfer"), provided that the details and duration of such transfer are reported to WPP for validation in accordance with procedures and information requirements specified in the Business Practice Manuals. Where such transfers have been duly reported and validated, an RA Transfer will be added to the purchasing Participant's Portfolio QCC and subtracted from the selling Participant's Portfolio QCC.

16.2.8 Planned Outages: Participants shall include in their Forward Showing Submittal for a Binding Season information on all Qualifying Resources that are currently out of service with a scheduled return date that falls during the Binding Season or after the Binding Season. Capacity associated with such resources must be deducted from Participants' Portfolio QCC as specified in the Business Practice Manuals to ensure no credit is granted for such resources during the planned outage. The aggregate of any additional outages that are planned to occur during the Binding Season but have not yet begun at the time of submission must be within the Participant's remaining surplus (or replaced with other supply). Participants may provide information on all Qualifying Resources that are planned to be out of service but if such data cannot be supplied with reasonable specificity, a Participant may provide a Senior Official Attestation at the time of the submission of its FS Submittal that it expects the sum of planned outages to be equal to or less than the surplus stated in its FS Submittal throughout the Binding Season.

16.2.8.1 If a Qualifying Resource is planned to return to service within the first five days of a Binding Season, WPP may approve a qualified acceptance of the FS Submittal, provided the deficiency is less than 500 MW.

16.2.8.2 A planned outage shall not justify a waiver of or exception to a Participant's holdback or energy delivery obligations under Part III of this Tariff. Participants will be expected to procure the necessary capacity or energy to meet the Operations Program requirements, regardless of planned outage schedules or FS Submittal acceptance.

16.3 FS Transmission Requirement

16.3.1 As part of its Forward Showing Submittal for a Binding Season, each Participant must demonstrate, as specified in the Business Practice Manuals, that it has secured firm transmission service rights, including under supply arrangements with a third party that holds or has committed transmission service rights, sufficient to deliver a MW quantity equal to at least 75% of the MW quantity of its FS Capacity Requirement. To the extent a Participant holds transmission service rights with a point of receipt at a Qualifying Resource, or in connection with an RA Transfer to such Participant, any such rights from such point in a MW quantity, respectively, in excess of the QCC of such Qualifying Resource, or in excess of the value of such RA Transfer, shall not contribute toward satisfaction of such Participant's FS Transmission Requirement. The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load. Notwithstanding the foregoing, authorized use of Capacity Benefit Margin will satisfy the FS Transmission Requirement. Demonstration of the FS Transmission Requirement shall not, in and of itself, relieve any Participant of responsibility for a Delivery Failure Charge as determined under Section 20.7 if such Participant's failure to obtain or maintain firm transmission service of the type and quantity expected by the Operations Program, as described in Section 20.6 of this Tariff, caused or contributed to an Energy Delivery Failure.

16.3.2 A Participant may include in its Forward Showing Submittal a request for an exception from a limited part of its FS Transmission Requirement, provided the exception request meets the terms, conditions, and limitations of one or more of the following four exception categories below. As more fully set forth in the Business Practice Manuals, such exceptions may be subject to overall WRAP limits, and shall be supported by a Senior Official Attestation. WPP will consider the exception category terms, conditions and limitations set forth below, and may consider the completeness of the

exception request, information from transmission service providers, OASIS data, and data readily available to WPP from other reliable and validated sources concerning the duration, timing, firmness and quantity of available transmission service or equivalent options (including transmission construction), in determining whether to grant or deny a transmission exception request. WPP shall provide such determination no later than sixty days after submission of such Participant's FS Submittal containing such transmission exception request. A Participant denied an exception request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested exception shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall give notice of any exception granted hereunder in the time and manner provided by the Business Practice Manuals. A Participant granted a transmission exception under either Section 16.3.2.1 or Section 16.3.2.2 must complete a monthly transmission exception check report demonstrating that either (i) the circumstances necessitating the exception have not changed; (ii) transmission has become available and the Participant has acquired it; or (iii) the Participant has acquired a different resource, and associated transmission service rights, and no longer requires the exception. Failure to timely submit a required monthly report will result in assessment of a Deficiency Charge, unless the deficiency is cured within seven days of notice of non-compliance.

16.3.2.1 Enduring Constraints. Participant is unable to demonstrate sufficient NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights on any single segment of a source to sink path for a Qualifying Resource; and Participant demonstrates that no ATC for such transmission service rights is available (either from the transmission service provider or through a secondary market) at the FS Deadline on the applicable segment for the Month(s) needed (for a duration of one year or less) at the applicable Open Access Transmission Tariff rate or less; and Participant submits a Senior Official Attestation that Participant has taken commercially reasonable efforts to procure firm transmission service rights, and that Participant has posted Firm Transmission Requirements on a relevant bulletin board prior to the FS Deadline. In the event such transmission service rights are only available for a duration of more than one year (whether from the transmission service provider or through a secondary market) at the FS Deadline on the applicable segment for the Month(s) needed at the applicable Open Access Transmission Tariff rate or less, a Participant is not required to obtain such service in order to qualify for the Enduring Constraints exception hereunder. Notwithstanding the foregoing, if such Participant declines to obtain such available service and is granted the exception hereunder, such Participant shall not qualify

for an exception hereunder for the same path (or across the same constraint) for the same season of the subsequent year if the Participant again declines to obtain such transmission service rights that are available for a duration of more than one year. In addition to the foregoing, Participant must further demonstrate that there was remaining available transmission transfer capability (i.e., non-firm ATC after the fact) for all CCHs in the same season of the most recent year for which CCHs have been calculated; or, if the path was constrained in at least one CCH of the CCHs in the same season of the most recent year for which CCHs have been calculated, Participant in that case must demonstrate either that it is constructing or contracting for a new local resource for at least the amount of the exception requested, or that it is pursuing long-term firm transmission service rights by entering the long-term queue and taking all appropriate steps to obtain at least the amount of the exception requested.

16.3.2.2 Future Firm ATC Expected. Participant demonstrates that ATC for NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights is not posted or available prior to the FS Deadline (for a duration of one year or less) at the applicable Open Access Transmission Tariff rate or less, and that the transmission service provider has, after the FS Deadline, released additional ATC for such transmission service rights in every one of the CCHs of the most recent year for which CCHs have been calculated on the applicable path. In the event ATC for such transmission service rights is only posted or available prior to the FS Deadline for a duration of more than one year (whether from the transmission service provider or through a secondary market) on the applicable segment for the Month(s) needed at the applicable Open Access Transmission Tariff rate or less, a Participant is not required to obtain such service in order to qualify for the Future Firm ATC Expected exception hereunder. Notwithstanding the foregoing, if such Participant declines to obtain such available service and is granted the exception hereunder, such Participant shall not qualify for an exception hereunder for the same path (or across the same constraint) for the same season of the subsequent year if the Participant again declines to obtain such transmission service rights that are available for a duration of more than one year. The Participant must also demonstrate that the exception request meets volume and duration limitations specified in the Business Practice Manuals.

16.3.2.3 Transmission Outages and Derates. Participant demonstrates that an applicable segment of its existing transmission service rights from its source to sink path for its Qualifying Resource is expected to be derated or out-of-service and the ATC

for NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights is not otherwise available, and that the exception request meets volume and duration limitations specified in the Business Practice Manuals.

16.3.2.4 Counterflow of a Qualifying Resource. Participant demonstrates that either: (i) Participant's use of firm transmission service in connection with the delivery of capacity from Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to Participant's load (or other qualifying delivery point permitted by the WRAP) or (ii) a second Participant's use of firm transmission service in connection with the delivery of capacity from the second Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to the second Participant's load (or other qualifying delivery point permitted by the WRAP) provides a direct and proportional counterflow transmission that supports the first Participant's delivery of capacity from the first Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to the first Participant's load (or other qualifying delivery point permitted by the WRAP) Qualifying Resource to their load. If the exception is requested under subpart (ii) of this subsection, the Participant requesting the exception shall include a written acknowledgement from the second Participant that it is aware of such exception request.

.

16.3.3 To the extent a Participant does not demonstrate satisfaction of its FS Transmission Requirement by the FS Deadline, the Participant may correct any such deficiency on or before the end of the cure period prescribed by Section 14.5 of this Tariff to avoid a Deficiency Charge.

16.3.4. Any deficiency of transmission service rights ultimately determined by WPP will be treated, for purposes of Deficiency Charge determinations, as in conjunction with, and not additive to, any deficiencies of QCC determined pursuant to Section 16.2.

17. Forward Showing Deficiency Charge

17.1 If a Participant fails during the cure period to demonstrate that it has resolved any identified deficiencies in either or both of its FS Capacity Requirement and its FS Transmission Requirement, the Participant will be assessed a Deficiency Charge for each Month for which a deficiency is identified in accordance with this section. In such case, the deficiency for which the Participant will be assessed a Deficiency Charge will be calculated in accordance with the following:

Participant's Monthly Capacity Deficiency = Maximum of (Monthly FS Capacity Requirement – Monthly Portfolio QCC, 0)

Participant's Monthly Transmission Deficiency (MW) = Maximum of ((75% × Monthly FS Capacity Requirement) – (Monthly Transmission Demonstrated + Approved Monthly Transmission Exemptions), 0)

Where Monthly Transmission Demonstrated is the amount of transmission service rights submitted by a Participant per the requirements in Section 16.3 and validated by WPP for each month.

Monthly Deficiency (MW) = Maximum of (Monthly Capacity Deficiency, Monthly Transmission Deficiency)

17.2 A Participant's Deficiency Charges shall be calculated as set forth in this Section 17.2, subject to the Transition Period rules in Section 17.3, and shall take account of multiple Monthly Deficiencies within a Forward Showing for a single Binding Season, multiple Deficiencies across a Forward Showing Year, consisting of a Summer Season and the immediately succeeding Winter Season, and any Monthly Deficiencies in a previous Forward Showing Year, in accordance with the following:

17.2.1 The Monthly Deficiency with the highest MW value in a Forward Showing for a Summer Season shall be assessed a Deficiency Charge equal to:

Max Summer Deficiency (MW) × Annual CONE ($/kW-year) × 1000 × Summer Season Annual CONE Factor

17.2.2 Any other Monthly Deficiency in the Participant's Forward Showing for the same Summer Season shall be assessed a Deficiency Charge equal to:

Additional Summer Deficiency (MW) × (Annual CONE ($/kW-year)/12) × 1000 × 200%

17.2.3 Any Monthly Deficiency in the Forward Showing for the immediately succeeding Winter Season with a higher MW value than the highest MW value of the Monthly Deficiency in the Summer Season shall be assessed a Deficiency Charge on the incremental MW value above the Summer Season equal to:

Maximum of (Max Winter Deficiency – Max Summer Deficiency, 0) (MW) × Annual CONE ($/kW-year) × 1000 × Winter Season Annual CONE Factor

and in such case where there is a Monthly Deficiency in the Winter Season with a higher MW value than the highest MW value of any Monthly Deficiency in the Summer Season, the Monthly Deficiency with the highest MW value in the Summer Season shall be assessed an additional Deficiency Charge calculated in accordance with Section 17.2.2.

17.2.4 Any other Monthly Deficiency in the Participant's Forward Showing Submittal for the same Winter Season shall be assessed a Deficiency Charge equal to:

Additional Winter Capacity Deficiency × (Annual CONE/12) × 1000 × 200%

17.2.5 For purposes of the above, CONE is the estimated cost of new entry of a new peaking natural gas-fired generation facility. The CONE estimate shall be based on publicly available information relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The CONE estimate shall not consider the anticipated net revenue from the sale of capacity, energy, or ancillary services from the hypothetical facility, nor shall it consider variable operating costs necessary for generating energy.

17.2.6 WPP shall review the CONE estimate annually for a possible update. Any proposed changes in the CONE estimate shall be subject to review through the stakeholder process for program rule changes.

17.2.7 The Summer Season Annual CONE Factor shall vary based on the ratio ("Summer % Deficit") of the Aggregate Capacity Deficiency for the WRAP as a whole for that Summer Season, divided by the P50 Peak Load Forecast for the Summer Season, as follows:

If the Summer % Deficit is less than or equal to 1%, the Summer Season Annual CONE Factor = 125%

If the Summer % Deficit is greater than 1% but less than or equal to 2%, the Summer Season Annual CONE Factor = 150%

If the Summer % Deficit is greater than 2% but less than or equal to 3%, the Summer Season Annual CONE Factor = 175%

If the Summer % Deficit is greater than 3%, the Summer Season Annual CONE Factor = 200%

17.2.8 The Winter Season Annual CONE Factor shall vary based on the ratio ("Winter % Deficit") of the Aggregate Capacity Deficiency for the WRAP as a whole for that Winter Season, divided by the P50 Peak Load Forecast for the Winter Season, as follows:

If the Winter % Deficit is less than or equal to 1%, the Winter Season Annual CONE Factor = 125%

If the Winter % Deficit is greater than 1% but less than or equal to 2%, the Winter Season Annual CONE Factor = 150%

If the Winter % Deficit is greater than 2% but less than or equal to 3%, the Winter Season Annual CONE Factor = 175%

If the Winter % Deficit is greater than 3%, the Winter Season Annual CONE Factor = 200%

17.2.9 Notwithstanding Sections 17.2.7 and 17.2.8, if a *Participant incurred any FS Deficiency Charges* in a Forward Showing Year *after the Transition Period*, then for the immediately following Forward Showing Year, both the Summer Season Annual CONE Factor and the Winter Season Annual CONE Factor shall be 200% *for such Participant*.

17.2.10. Subject to the Transition Period rules in Section *15A.1*, revenues from the payment of Deficiency Charges as to a Binding Season shall be allocated among those Participants with no Deficiency Charges for that Binding Season, pro rata based on each Participant's share of all such Participants' Median Monthly P50 Peak Loads for such Binding Season.

17.3 During the Transition Period, Deficiency Charges otherwise calculated under Section 17.2 shall be reduced as, when, and to the extent, and subject to the conditions, provided in Section 17.3.2; and revenue allocations otherwise calculated under Section 17.2 shall be adjusted as, when, and to the extent, and subject to the conditions, provided in Section 17.3.4.

17.3.1. During the Transition Period, a Participant with a Monthly Capacity Deficiency can pay a *Discounted* Deficiency Charge for so much of such Monthly Capacity Deficiency as was due to an Excused Transition Deficit. To obtain an Excused Transition Deficit for a Binding Season, the Participant must provide a Senior Official Attestation attesting that the Participant *or a relevant third party servicing load for which the Participant is the LRE* has made commercially reasonable efforts to secure Qualifying Resources in the quantity needed to satisfy the Participant's FS Capacity Requirement for the Binding Season, but is unable to obtain Qualifying Resources in the quantity required for the Binding Season because the supply of such resources on a timely basis and on commercially reasonable

terms is at that time inadequate. *If the attestation relates to a third-party servicing load for which the Participant is the LRE, the Senior Official Attestation may be signed by a Senior Official of the third party load service provider, as further detailed in the Business Practices.* Excused Transition Deficits are not resource specific, relate to a MW quantity of the Participant's FS Capacity Requirement, and are limited for each Participant as to a Binding Season during the Transition Period to a maximum permissible MW quantity equal to a percentage value times the FSPRM applicable to such Participant for all Forward Showing Submittals submitted by such Participant for such Binding Season. For purposes of such calculation, the percentage value is*: 200*% for each of the *2027* Summer Season and *2027-2028* Winter Season*; and 100*% for each of the *2028* Summer Season and *2028-2029* Winter Season.

17.3.2 A Participant will pay a *Discounted* Deficiency Charge as to the portion of its Monthly Capacity Deficiency for which it obtained an Excused Transition Deficit. The *FS* Deficiency Charge otherwise applicable to such Participant under Section 17.2 shall be reduced by a percentage value equal to 75% for each of the *2027* Summer Season and *2027-2028* Winter Season*; and* 50% for each of the *2028* Summer Season and *2028-2029* Winter Season. The Participant will be assessed a*n FS* Deficiency Charge calculated under Section 17.2, without reduction or adjustment, for any of its Monthly Capacity Deficiency that is in excess of the amount of such deficiency for which it obtained an Excused Transition Deficit.

17.3.3 Whether or not a Participant obtains an Excused Transition Deficit as to a Binding Season, the Participant may reduce a Monthly Capacity Deficiency otherwise calculated under Section 17.1 for a Binding Season during the Transition Period to the extent such deficiency is due to the Participant's inability to obtain assent from the supplier under a Legacy Agreement to the accreditation required for such Legacy Agreement under Part II of this Tariff and the Business Practice Manuals. To obtain such relief, the Participant must provide a Senior Official Attestation attesting that the Participant made commercially reasonable efforts to execute the required accreditation form with the supplier under the Legacy Agreement, but the supplier was unable or unwilling to counter sign the accreditation form. The reduction in Monthly Capacity Deficiency permitted by this Section 17.3.3 as to any Participant for all Forward Showing Submittals submitted by such Participant for any Binding Season during the Transition Period shall not exceed a MW quantity equal to 25% times the FSPRM applicable for such Participant for such Binding Season. To the extent a Participant reduces a Monthly Capacity Deficiency under this subsection, the percentage of the Participant's FSPRM corresponding to the reduction hereunder shall reduce the maximum permissible percentage of FSPRM reduction allowed under Section 17.3.1 for Excused Transition Deficits for the same Binding Season.

17.3.4 A Participant that, as a result of application of this Section 17.3, pays no Deficiency Charge as to a Binding Season, shall not be deemed a "Participant[ ] with no Deficiency Charges" for purposes of Section 17.2.10, and shall not receive an allocation of revenues from the payment of Deficiency Charges as to such Binding Season.

PART III OPERATIONS PROGRAM

18. Operations Program Overview

18.1 The Operations Program facilitates access to collective capacity made available through regional load and resource diversity of all Participants under the terms of this Part III.

18.2 The Operations Program evaluates forecasted system conditions across the seven-day period ("Multi-Day-Ahead Assessment") preceding the Operating Day, commencing at the outset of the assessment period with an initial Sharing Calculation and initial identification of potential Sharing Events for the Operating Day. The assessment is refined as forecasted conditions for the Operating Day are revised and established on the Preschedule Day, a Holdback Requirement for any Sharing Events is then identified. To the extent a Sharing Event continues to be identified for the Operating Day, Holdback Requirements shall be converted into Energy Deployments on the Operating Day.

18.3 The Operations Program prescribes pricing designed to incent Participants to resolve any forecast Operating Day deficiencies before the Operating Day, including through transactions outside the Operations Program, and to fully compensate Participants that provide support through the Operations Program to Participants with Operating Day deficiencies.

19. Operations Program Timeline and Supporting Information

19.1 The Operations Program includes a Multi-Day Ahead Assessment that looks ahead at the next seven Operating Days by performing an indicative Sharing Calculation from Participant forecast data for each future Operating Day up until the Preschedule Day. The Sharing Calculation for the Preschedule Day is not indicative but is binding, subject to Sections 20.2.4 and 20.3. Participants shall provide WPP with forecasts for the next seven Operating Days of expected (i) load, (ii) output of VERs, (iii) output of RORs, (iv) Contingency Reserves, and (v) forced outages, including outages on transmission facilities the Participant utilized to meet its Forward Showing Capacity Requirement, as further described in the Business Practice Manuals. WPP shall utilize the forecast data obtained in the Multi-Day-Ahead Assessment to calculate or revise the indicative Sharing Calculations for each day thereafter, up until the Preschedule Day, and will use such forecast data to revise the indicative Sharing Calculation hourly during the Operating Day. Such forecast data will also be used to calculate the binding Sharing Calculation for the Preschedule Day.

19.2 The Operations Program, during any Binding Season, shall rely on and employ (among other data) the following information from the Forward Showings for such Binding Season: (i) the P50 Peak Load Forecast for each Participant; (ii) the Monthly FSPRMs for each Participant during such Binding Season; (iii) expected performance by Qualifying Resource type and any RA Transfers; (iv) expected forced outage rates by resource type; (v) expected Contingency Reserves; and (vi) firm transmission service rights made available for purposes of regional diversity sharing under the WRAP, permitted under Part II of this Tariff, which shall be assumed to be available for all hours of each Month for which such firm transmission service rights were made available.

19.3 To facilitate WPP's conduct of the Multi-Day-Ahead Assessment, each Participant shall provide the Program Operator information relevant to the Participant's expected demand and supply conditions on each Operating Day, of the type, in the manner, and with the frequency, specified in the Business Practice Manuals.

19.4 Each Participant in any Subregion identified in the Business Practice Manuals as not containing a central transmission hub permitting energy deliveries to that hub from any point within such Subregion, shall, in addition to providing the information required by Section 19.3, identify, on or before the deadline during the Preschedule Day specified in the Business Practice Manuals, for each Hour of the Operating Day each point to which it can deliver energy, each point at which it can take receipt of energy, the quantity it can deliver or receive at each such point, and a numeric factor intended to prioritize use of transmission made available by Participants with positive Sharing Calculations and needed by Participants with negative Sharing Calculations for each such hour. A Participant with a positive Sharing Calculation for an hour must provide a total quantity for all identified points at which it can deliver that is no less than the amount of its positive Sharing Calculation for such hour (adjusted as necessary for any RA Transfer in accordance

with Section 20.1.2). A Participant with a negative Sharing Calculation for an hour must provide a total quantity for all identified points at which it can take receipt that is no less than the amount of its negative Sharing Calculation for such hour (adjusted as necessary for any RA Transfer in accordance with Section 20.1.2). Participants shall provide this same information for each Operating Day on an expected or preliminary basis on each day of the Multi-Day-Ahead Assessment following, and based on, the expected Holdback Requirement estimates provided on each such day for the Operating Day.

19.5 Any Participant with excess supply that is not obligated to the WRAP through a positive Sharing Calculation result may, at its sole election, offer such supply to the WRAP as Voluntary Holdback. If the offering Participant has a positive Sharing Calculation result, the offered capacity shall be in addition to that Sharing Calculation result; if the offering Participant has a negative Sharing Calculation result, the offered capacity will only be included in the allocation of Holdback Requirement so long as the offering Participant did not confirm a need for Holdback Capacity for such hour. Such offers must be submitted within the time window identified in the Business Practice Manuals, must include the information identified in Sections 19.3 and 19.4, as applicable, and must conform to the format and content identified in the Business Practice Manuals. An offer of Voluntary Holdback may become part of the Participant's Holdback Requirement when it is included in the allocation on the Preschedule Day prescribed by Section 20.2.

20. Components of the Operations Program

20.1 Sharing Calculation

20.1.1 WPP shall implement, as more fully described in the Business Practice Manuals, with respect to each Forward Showing Submittal accepted by WPP for a Participant under Part II of this Tariff, or with respect to each Subregion in which the Participant is responsible for load regardless of whether the Participant submitted a single Forward Showing Submittal encompassing its loads in both Subregions, the following Sharing Calculation to identify any hour in which any Participant is forecast to have a capacity deficit (known as a "Sharing Event"). This calculation takes into account changes in a Participant's resource availability, resource performance, forecast load, and Contingency Reserve relative to the Forward Showing, plus an Uncertainty Factor. The Sharing Calculation is equal to:

[(P50) * (1 + FSPRM) + Contingency Reserve Adjustment] – [Load Forecast – Demand Response Capacity Resources + Contingency Reserve Obligation + Uncertainty Factor] + [ΔForced Outages + ΔRoR Performance + ΔVER Performance]

Where:

P50 refers to the Participant's Monthly P50 Peak Load for that Binding Season's Month;

FSPRM, as described in Section 16.1.2, is an increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages and is expressed as a percentage of the applicable Participant P50 Peak Load Forecast for that Binding Season's month;

Contingency Reserve Adjustment accounts for changes in Contingency Reserve expectations (relative to the 6% Contingency Reserve assumed in the FSPRM) resulting from energy contract purchases and contract sales as set forth in the Business Practice Manuals;

Load Forecast refers to the forecast of expected load for the subject hour for the loads for which the Participant is the Load Responsible Entity and that have not been excluded from WRAP participation;

Demand Response Capacity Resource as described in Section 16.2.5.4.

Contingency Reserve Obligation refers to the amount of Contingency Reserve the Participant is carrying during the operating hour equal to (i) 3% of Load Forecast for which the Participant is the WRAP LRE and maintains

its Contingency Reserve, (ii) plus 3% of WRAP load for which the Participant is not the LRE but has assumed the Contingency Reserve through a contractual arrangement, (iii) plus 3% of generation used to meet any load for which the Participant is the LRE and maintains the Contingency Reserve, (iv) plus 3% of generation utilized to meet WRAP Load for which the Participant is not the LRE but has assumed the Contingency Reserve through a contractual arrangement;

Uncertainty Factor refers to a factor determined by WPP, as more fully set forth in the Business Practice Manuals, to account for the potential variance between forecasts of load, solar resources, wind resources, and run-of-river resources, and the Operating Day conditions of such load and resources;

Δ Forced Outages refers, for the subject hour, to the sum of:

(i) any change in forced outages of any of the thermal resources included in the Participant's Portfolio QCC, relative to the forced outages assumed in the Forward Showing Submittal by application of the Forced Outage Factor; plus

(ii) any change in forced outages of any of the Storage Hydro Qualifying Resources relative to the forced outages assumed in the calculation of the Participant's Resource QCC as more fully described in the Business Practice Manuals; plus

(iii) any reduction in output capability of any of the Energy Storage Resources due to equipment failure or protection
   a. In the first four (4) hours the Forced Outages MWs that can be claimed are equal to [(charge MW x duration)/4]
   b. For all hours beyond four (4) hours, the Forced Outages MW amount that can be claimed for an Energy Storage Resource shall not be greater than the monthly QCC; plus

(iv) any impacts of transmission conditions on previously acquired firm transmission service rights that result in capacity reductions up to the level of the Resource QCC of the associated Qualifying Resource;

ΔRoR Performance refers to any change, for the subject hour, in expected performance of any of the run-of-river resources in the Participant's Portfolio QCC relative to the QCC of those Qualifying Resources; and

ΔVER Performance refers to any change, for the subject hour, in expected performance of the VER Resources in the Participant's Portfolio QCC relative to the QCC of those Qualifying Resources;

20.1.2 In addition to the foregoing, the Sharing Calculation for a Participant that is a purchaser of an RA Transfer shall be performed in two passes, with and without such purchase. If the result of assuming in the first pass that the Participant had not purchased the RA Transfer is that the Participant has a

negative Sharing Calculation, then the Participant that sold the RA Transfer must agree, for the time period addressed by the Sharing Calculation, to an energy delivery to the Participant that purchased the RA Transfer, in an amount equal to the lesser of: (i) the MW quantity needed to result in a net zero Sharing Calculation for the Participant that purchased the RA Transfer; and (ii) the MW amount of the RA Transfer. If the result of recognizing the Participant's purchase of the RA Transfer in the second pass is that the Participant has a positive Sharing Calculation, then the Participant that sold the RA Transfer must assume a share of the purchasing Participant's resulting obligation to the Operations Program in an amount equal to the MW quantity of the RA Transfer, minus the MW quantity of the delivery made by the seller of the RA Transfer to the purchaser of the RA Transfer as a result of the first pass.

20.1.3 The Sharing Calculation of any Participant that was found to have a Monthly Capacity Deficiency under Sections 16.1 and 16.2, for which such Participant paid a Deficiency Charge, including any Deficiency Charge reduced by application of Section 17.3 during the Transition Period, shall be reduced by the MW quantity of such Monthly Deficiency.

20.2 Holdback Requirement

To the extent that: (i) WPP's application of the Sharing Calculation identifies on the Preschedule Day a Sharing Event for any hour(s) of the Operating Day; and (ii) the Participant(s) found to be deficient for such hour(s) by the Sharing Calculation confirms to WPP on the Preschedule Day, in accordance with notification and confirmation procedures set forth in the Business Practice Manuals, such Participant's need for capacity for such hour(s), then WPP shall determine the Participants having a Holdback Requirement for such hour(s) and the quantity of the Holdback Requirement for each such Participant in accordance with this Section 20.2. The Operations Program will prioritize offers of Voluntary Holdback in the allocation and assignment of Holdback Requirements. Holdback Requirements shall be expressed as whole MWs for each hour for which they are estimated or established and shall not be specific to any Qualifying Resource.

20.2.1 Subregion with Central Hub

For any hour, as to any Subregion identified in the Business Practice Manuals as containing a central transmission hub permitting energy deliveries to that hub from any point within such Subregion ("Central Hub"), the aggregate of the holdback needed to meet the requirements of all Participants with negative Sharing calculation results that have confirmed their need for holdback will be allocated and assigned first among offers of Voluntary Holdback, and second, to the extent such needs remain unmet, among Participants with positive Sharing Calculation results.

20.2.1.1 Allocation of Voluntary Holdback: Voluntary Holdback will be allocated in one of three alternative ways, based on comparing the aggregate confirmed need for holdback among Participants with negative Sharing Calculation results against the aggregate of all offers for Voluntary Holdback.

20.2.1.1.1 If the total MW quantity of all Voluntary Holdback offered is equal to the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant that offered Voluntary Holdback is assigned its offered Voluntary Holdback as its Holdback Requirement.

20.2.1.1.2 If the total MW quantity of all Voluntary Holdback offered is more than the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant that offered Voluntary Holdback is assigned as its Holdback Requirement a percentage of the total confirmed need for holdback based on the ratio of the Participant's MWs of offered Voluntary Holdback to the sum of all Participants' MWs of offered Voluntary Holdback.

20.2.1.1.3 If the total MW quantity of all Voluntary Holdback offered is less than the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant's Holdback Requirement is determined as set forth in section 20.2.1.2.

20.2.1.2 Allocation of Remaining Holdback Requirement: Sharing Calculation Results

If the total MW quantity of all Voluntary Holdback offered is less than the total MW quantity of all deficient Participants' confirmed requests for holdback, then the maximum Voluntary Holdback offered is used as the first term in the Holdback Requirement. The remaining term of the Holdback Requirement is met by application of the Sharing Calculation, and the results of the two terms are summed for each Participant. The remaining need for holdback that is not met by Voluntary Holdback is allocated among all Participants with positive Sharing Calculation results pro rata based on the ratio for each Participant of the Participant's positive Sharing Calculation result to the sum of the positive Sharing Calculation results. The

sum of these two values for each applicable Participant is the Holdback Requirement for that Participant.

20.2.2 Subregion without Central Hub

For any hour, any Subregion not containing a Central Hub, the Program Operator shall conduct an optimization-based allocation to pair surplus and deficient Participants. The allocation methodology will utilize the points at which surplus Participants can deliver their Holdback Requirement, the points at which deficient Participants can take receipt of their allocation of the total Holdback Capacity, and the transfer capability that exists to the points at which surplus Participants can deliver and the points at which deficient Participants can take receipt.

The optimization will generally attempt to prioritize (i) Voluntary Holdback; (ii) Holdback Capacity matched pursuant to the information provided per Section 19.4 on a nearest neighbor and cluster basis, allocated pro rata among Participants within such cluster; (iii) Holdback Capacity matched pursuant to the information provided and allocated among Participants within the same Subregion to the extent not matched and allocated under category (ii); and finally (iv) Holdback Capacity from Participants in another Subregion, paired with any transmission service per Section 14.3.2.

20.2.3 Absent a Holdback Requirement Transfer as described below, a Participant's Holdback Requirement for any hour of an Operating Day shall not exceed the level first set by WPP on the Preschedule Day for that Participant for that hour.

20.2.4 Any Participant may agree with any other Participant for the first Participant to transfer to the second Participant some or all of the Holdback Requirement established for the first Participant for any hour on any Operating Day. Any such Holdback Requirement Transfer shall be a bilateral arrangement settled outside the Operations Program, provided, however, that both Participants must timely notify WPP, by the time and in the manner described in the Business Practice Manuals, of such Holdback Requirement Transfer. Any necessary transmission arrangements and any transaction settlements shall be the sole responsibility of the Participants that are the parties to such bilateral arrangement.

20.2.4.1 No Holdback Requirement transfer for any hour shall be permitted if notice of such bilateral transaction is not fully reported to WPP, in the form required by the Business Practice Manuals, by 120 minutes before the start of such hour.

20.3 Release of Surplus Capacity

20.3.1 As detailed in the Business Practice Manuals, WPP will review the indicative Sharing Calculation results from the Multi-Day Ahead Assessment and to the extent the WPP determines any indicative Sharing Calculations can be reduced, it may release all or a portion of Participants' future Holdback Requirements. WPP may permit a release of future Holdback Requirements to the extent WPP has not applied a Safety Margin for such hour and (i) WPP's continued Sharing Calculations determine that no Participant has a negative indicative Sharing Calculation result for such hour; and (ii) WPP determines there is a low probability of a Sharing Event for the hour; or (iii) WPP grants a Participant's request for extenuating circumstances of all or any portion of that Participant's future Holdback Requirement for the hour.

20.3.2 Upon release of all or any portion of a future Holdback Requirement, the quantity of future Holdback Requirement so released shall no longer be subject to an Energy Deployment requirement under the Operations Program for the subject hour.

20.4 Energy Deployment

20.4.1 Participants shall provide energy during an hour, in support of any Participants with a negative Sharing Calculation result and a confirmed need for energy under the Operations Program for such hour, in accordance with WPP's calculation of the Energy Deployment for such hour. The total Energy Deployment required of all Participants that are subject to Energy Deployment shall equal the sum, in MWh for that hour, of the energy confirmed as being needed in that hour by Participants in such Subregion with negative Sharing Calculation results in such hour, to the extent that can be supported by the Program. The Energy Deployment assigned to each Participant shall not exceed that Participant's Holdback Requirement calculated on the Preschedule Day, adjusted for any applicable transfer of Holdback Requirement as allocated and assigned for the Preschedule Day, and, as further adjusted to reflect the election, made after the Preschedule Day, of any Participant with a negative Sharing Calculation result on the Preschedule Day to decline all or any part of the Holdback Capacity to which it would have been entitled based on the Holdback Requirements determined on the Preschedule Day.

20.4.1.1 In Subregions with a Central Hub, Energy Deployments required hereunder shall be delivered to the Central Hub in such Subregion, or to an alternate delivery point mutually agreed by the parties to a specific Energy Deployment, provided both parties to the transaction report such alternative delivery arrangements to WPP in the form and manner described in the Business Practice Manuals.

20.4.1.2 In Subregions without a Central Hub, Energy Deployments required hereunder shall be delivered to the receipt point and delivery point as indicated by the optimization allocation, or to an alternate delivery point mutually agreed by the parties to a specific Energy Deployment, provided both parties to the transaction report such alternative delivery arrangements to WPP in the form and manner described in the Business Practice Manuals.

20.4.2 The Energy Deployment a Participant may receive for any hour shall be no greater than the negative Sharing Calculation result calculated for such Participant for such hour. Such Participant shall confirm, by no later than 85 minutes before the start of such hour, the quantity of Energy Deployment for which it requires delivery for such hour, through the procedures outlined in the Business Practice Manuals. Any Participant that does not confirm required Energy Deployment deliveries for such hour by such deadline will be deemed to waive all deliveries of Energy Deployment under the Operations Program for such hour.

20.4.3 The Energy Deployment a Participant can be required to supply for an hour shall not exceed the final Holdback Requirement calculated for such Participant on Preschedule Day, including any duly reported exchange of Holdback Requirement, as of 85 minutes before the start of such hour.

20.4.4 WPP shall advise each Participant with a required Energy Deployment for an hour of the required MWh quantity and delivery point of such Energy Deployment by no later than 80 minutes before the start of such hour.

20.5 Safety Margin

20.5.1 WPP may establish on the Preschedule Day a Safety Margin for the WRAP Region or any identified Subregion thereof for any hour of an Operating Day when warranted by such circumstances as potential large resource trips, heavy transmission outage conditions, significant environmental conditions, or other similar regional or subregional conditions, as more fully set forth in the Business Practice Manuals.

20.5.2 Any Safety Margin so determined for an hour shall be allocated pro rata among Participants with a positive Sharing Calculation result, based on their relative shares of the sum of all positive Sharing Calculation results for such hour, provided, however, that the Safety Margin allocated to a Participant may not result in a Holdback Requirement for such Participant greater than such Participant's Sharing Calculation result. A Participant allocated holdback for a Safety Margin hereunder does not receive compensation under this Tariff for such allocation of holdback.

20.5.3 WPP shall notify all Participants of application of a Safety Margin for any hour, including in such notice the total timeframe, the MW amount, and the rationale for such Safety Margin.

20.6 Operations Program Transmission Service Requirements

Participant shall have in place, prior to the Operating Day, transmission service satisfying NERC Priority 6 or 7 for each hour of such Operating Day for which a Sharing Event has been established, in a quantity sufficient for deliveries from the Qualifying Resources relied upon in such Participant's Forward Showing Submittal to demonstrate satisfaction of such Participant's FS Capacity Requirement (or from replacement Qualifying Resources) to serve such Participant's loads during such hours. In the event a Participant has an Energy Delivery Failure, the review associated with the possible assessment of a Delivery Failure Charge on such Participant shall, as further described in the Business Practice Manuals, include whether a failure to secure sufficient NERC Priority 6 or Priority 7 firm transmission service rights caused or contributed to such Energy Delivery Failure. For such purpose, the Participant will have been expected to have complied with the transmission service requirement stated in this subsection.

20.7 Failure to Deliver Energy Deployments

20.7.1 A Participant assigned a required Energy Deployment pursuant to Section 20.4.4 of this Tariff for any hour that fails to deliver the specified energy during such hour, and that does not obtain a waiver of its Energy Deployment obligation, shall be assessed a Delivery Failure Charge.

20.7.2 A Participant shall be deemed to have an Energy Delivery Failure if Participant fails to deliver the Energy Deployment quantity established under Section 20.4.1, absent grant of a waiver pursuant to Section 20.7.3 of this Tariff.

20.7.3 A Participant anticipating an Energy Delivery Failure should provide WPP notice of such expected Energy Delivery Failure as soon as practicable after becoming aware of the anticipated failure. Whether anticipated or not, a Participant may request a waiver of an Energy Deployment obligation after an Energy Delivery Failure has occurred. The WPP shall review all such waiver requests and shall determine whether the Participant's justification for the Energy Delivery Failure is valid and warrants waiver of its Energy Deployment obligation. The WPP also shall consider whether the Participant knew in advance, or reasonably should have known in advance, of an Energy Delivery Failure, and what efforts the Participant took to notify the WPP in advance of such Energy Delivery Failure. The procedures for addressing such waiver requests, including a non-exclusive list of valid justifications for an Energy Delivery Failure shall be set forth in the Business Practice Manuals. A Participant denied a waiver request hereunder may appeal such denial to the Board of Directors in accordance

with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested waiver shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall report on the disposition of each waiver request received.

20.7.4 The Delivery Failure Charge for each hour shall be the Charge Rate applicable for such hour times the MWhs of energy that were required to be, but were not, delivered pursuant to an Energy Deployment during such hour. The Charge Rate shall be the higher of the Day-Ahead price or Real-Time price provided by the Day-Ahead Applicable Price Index and Real-Time Applicable Price Index as specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery, respectively, for the hour, times a Delivery Failure Factor, as follows:

20.7.4.1 If the deficit is fully covered by other Participants through the Operations Program, in each instance of failure, the Delivery Failure Factor shall be five for the first non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; ten for the second non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; and twenty for the third and subsequent non-waived Energy Delivery Failures in a Cumulative Delivery Failure Period. For purposes of applying the Delivery Failure Factors under this Section 20.7.4 or the review referenced in Section 20.7.5, multiple Energy Delivery Failures occurring in one day shall be treated as a single instance of failure.

20.7.4.2 If the deficit is not fully covered by other Participants through the Operations Program, the Delivery Failure Factor is twenty-five for the first non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; and fifty for the second and subsequent non-waived Energy Delivery Failures (regardless of whether the prior instance(s) of delivery failure were fully covered by other Participants) in a Cumulative Delivery Failure Period.

20.7.4.3 Revenues from Delivery Failure Charges assessed in cases where the deficit was fully satisfied by other Participants will be used to reduce WPP costs that are recovered under Schedule 1, WRAP Administration Charge. Revenues from Delivery Failure Charges assessed in cases where the deficit was not fully met by other Participants will be collected by the WPP and provided to the Participant that had an unserved deficit.

20.7.4.4 Notwithstanding anything to the contrary in this Section 20.7.4, the Delivery Failure Charges assessed on a Participant, regardless of application of the Delivery Failure Factor, shall not

exceed, over the course of a Summer Season and the immediately succeeding Winter Season, the dollar amount that, as more fully detailed in the Business Practice Manuals, would have been assessed cumulatively under Section 17 as Deficiency Charges if the Participant had one or more Forward Showing Capacity Deficiencies over the course of such Summer Season and Winter Season in the same MW amounts as the highest MW amount of Delivery Failure experienced by such Participant in each Month of such Summer Season and Winter Season. The maximum dollar amount described herein shall be calculated on an ongoing basis during such Summer Season and Winter Season, and increased or reduced accordingly, without awaiting the end of the combined period of such Summer Season and Winter Season.

20.7.5 In addition to assessment of the Delivery Failure Charge, a third or subsequent instance of non-waived delivery failure, when all such delivery failures are fully covered by other Participants, or a second or subsequent instance of non-waived delivery failure when such instance is not fully covered by other Participants, will subject the Participant to review for expulsion from the WRAP.

20.8 Voluntary Response to Increased Deficiencies Identified After Preschedule Day

20.8.1 A Participant that identifies an unmet need for energy for any hour of an Operating Day that is outside of assistance provided or to be provided by Holdback Requirements or Energy Deployments established hereunder may, in accordance with procedures specified in the Business Practice Manuals, notify WPP of the need for such assistance. WPP will establish a portal or other procedure, as specified in the Business Practice Manuals, to facilitate provision of assistance, on a voluntary, bilateral basis, by other Participants to the Participant that identified the unmet need. Compensation, terms, and conditions of any resulting bilateral transactions will be determined by the affected parties outside of this Tariff. While Participant response to any such notification is voluntary, Participants are encouraged to provide assistance to other Participants in the circumstances described in this subsection, in consideration of the mutual support each Participant has agreed to provide to each other Participant by its agreement to participate in the WRAP, including this Operations Program.

21. Operations Program Settlements

21.1 Nature of Operation Program Settlements

21.1.1 Operations Program settlements are bilateral transactions; they are not purchases from or sales to a central market.

21.1.2 Operations Program transactions use existing transaction systems and processes.

21.1.3 The WPP will calculate and post settlement quantities and prices based on the Energy Deployment and Holdback Requirement, in accordance with procedures specified in the Business Practice Manuals for provision of transaction information by and among Participants and WPP, but WPP has no role in the transaction itself. WPP is not a settlement entity.

21.1.4 Settlement Prices calculated under Section 21.2 shall recognize pricing differences among Subregions. Where the seller and buyer are located in the same Subregion, the Applicable Price Index shall be the price index specified for that Subregion in the Business Practice Manuals. Where the seller and buyer are located in different Subregions, the following components of the settlement price calculation in Section 21.2 will be calculated using the Applicable Price Index for the Subregion that provides the higher index price: (i) Possible Block Sale Revenue; (ii) Total Settlement Price; (iii) Energy Declined Settlement Price; and (iv) Realtime Value of Unheld Energy. If a third participant is involved by providing transmission service rights between Subregions, the Participant that provided holdback or Energy Deployment shall receive the settlement price of the Subregion from which the holdback or Energy Deployment was sourced, and the Participant that provided Subregion to Subregion transmission service rights pursuant to Section 19.4 shall receive the difference between each Subregion's Total Settlement Price, or zero, whichever is greater.

21.2 Settlement Price Calculation. Settlement prices shall be calculated in accordance with the following, as more fully set forth in the Business Practice Manuals.

21.2.1 A Participant assigned a Holdback Requirement on a Preschedule Day for any hour of an Operating Day shall be paid the Holdback Settlement Price times the MW quantity of the Holdback Requirement. A Participant that provides energy to another Participant pursuant to an Energy Deployment shall be paid the Energy Declined Settlement Price, defined in Section 21.2.4, times the MWhs of energy provided to such other Participant, and its total payments shall be reduced by the Energy Declined Settlement Price times the MWhs of energy that would have been provided under a Holdback Requirement but were declined by the other Participant. A Participant

assigned a Holdback Requirement also shall be paid, when applicable, a Make Whole Adjustment, as provided below in Section 21.2.5.

21.2.2 A Participant that had a negative Sharing Calculation result for any hour of an Operating Day, which was incorporated in the calculation of Holdback Requirements of any Participants for such hour, determined as of the Preschedule Day, shall pay the Holdback Settlement Price times the MW quantity of such negative Sharing Calculation result. In addition, any Participant that had a negative Sharing Calculation result that was incorporated in the calculation of a Holdback Requirement shall contribute to the payment of the Make Whole Adjustment based on its negative Sharing Calculation. A Participant that declines energy that would have been provided under a Holdback Requirement shall be credited the Energy Declined Settlement Price times the MWhs of energy declined by such Participant.

21.2.3 The Holdback Settlement Price shall equal the Total Settlement Price minus the Energy Declined Settlement Price.

21.2.4 The Energy Declined Settlement Price shall equal the Applicable Real-Time Index Price for the hour.

21.2.5 The Make Whole Adjustment is applied in the event that the settlement revenue and the estimated value of the non-dispatched energy is less than the estimated revenues the selling entity would have received had such entity not been subject to a Holdback Requirement and had sold a day-ahead block of energy with a MW value equal to the maximum amount of Holdback Requirement for the hours in the block. The Make Whole Adjustment has a minimum value of zero and is determined as follows:

Make Whole Adjustment (when applicable) =
Maximum of (Possible Block Sale Revenue
– Final Settlement Revenue
– Realtime Value of Declined Energy
– Realtime Value of Unheld Energy, 0)

Where:

Realtime Value of Declined Energy = Energy Declined × Energy Declined Settlement price

provided that Declined Energy is only applicable to those hours where there was a positive Holdback Requirement.

Realtime Value of Unheld Energy = (Maximum Holdback MW in Block – Holdback MW Requested) × Applicable Index Price

21.2.6 The Total Settlement Price used in the above calculations shall be determined in accordance with the following formula:

Total Settlement Price = Maximum of (Minimum of (Hourly Shaping Factor × Day Ahead Applicable Index Price × 110%, 2000 $/MWh), 0)

where:

Hourly Shaping Factor is based on the most recent High-Priced Day for the relevant season, defined as a day in which at least one hour has a system marginal energy cost ("SMEC") greater than $200/MWh, and shall be calculated as follows:

1 + {[CAISO Hourly Day Ahead SMEC - CAISO Average Day Ahead SMEC (on- or off-peak hours)] / [CAISO Average Day Ahead SMEC (on- or off-peak hours)]}

Day-Ahead Applicable Index Price is the day-ahead heavy load/light load ICE Index price that is specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery. If transmission via Section 14.3.2 was used to facilitate holdback, the Applicable Index Price shall be the higher of the two subregional day-ahead index prices for that portion of the holdback.

Real-Time Applicable Index Price is the real-time index price that is specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery.

SCHEDULE 1

WESTERN RESOURCE ADEQUACY PROGRAM ADMINISTATIVE COST RECOVERY CHARGE

The Western Power Pool's Costs of administering and operating the Western Resource Adequacy Program including, without limitation, all costs incurred or obligated by WPP as Program Administrator, all costs paid or payable by WPP to the Program Operator or other service providers, all costs of the Board of Directors in directing, supervising, or overseeing the WRAP, and the costs of maintaining a reasonable reserve as provided in Section 1 of this Schedule 1, shall be recovered from Participants pursuant to the charges set forth in this Schedule 1.

Section 1. WRAP Costs

1. As used herein, Costs shall mean WPP's costs, expenses, disbursements and other amounts incurred (whether paid or accrued) or obligated of administering and operating the WRAP as described above, including, without limitation, operating expenses, general and administrative expenses, costs of outside services, taxes, fees, capital costs, depreciation expense, interest expense, working capital expense, any costs of funds or other financing costs, and the costs of a reasonable reserve as provided herein.
2. The Costs included in a WRAP Administration Charge assessed for a Month shall be the Costs determined as being incurred for that Month, including, without limitation, for each Month, one-twelfth of any annual charge(s).

3. The Costs included in the WRAP Administration Charge for a reasonable reserve shall be those designed to establish over the first twelve months that this WRAP Administration charge is in effect an amount equal to 6% of the expected Costs, exclusive of such reserve, for one year; and to maintain such reserve thereafter at an amount equal to 6% of the expected Costs, exclusive of such reserve for the then-current year. WPP shall record on its income statement deferred regulatory expense, and WPP's balance sheet will reflect as a cumulative deferred regulatory liability, revenues collected under this Schedule 1 that are in excess of the Costs exclusive of such reserve and taking account of and including any accrued tax expense effects of this regulatory liability. The deferred regulatory liability will be reduced when after-tax WPP revenues collected under this Schedule 1 during any Month are less than the Costs exclusive of such reserve. Within thirty days after the end of each Year, to the extent WPP determines that the deferred regulatory liability exceeds 6% of WPP's revenues that were collected under this Schedule 1 during such Year, such excess amounts in the deferred regulatory liability shall be refunded evenly over the applicable billing determinant volumes in the remainder of the subsequent Year through credits to charges to then-current customers under this Schedule 1.

Section 2. WRAP Administration Charge

Each Participant shall be assessed each Month a WRAP Administration Charge equal to the sum of the Base Charge and the Load Charge,

where:

The Base Charge for each Participant equals the Base Costs divided by the number of Participants being assessed the Base Charge for the Month for which the WRAP Administration Charge is being calculated;

The Load Charge for each Participant equals the Load Charge Rate of the Load Services Costs divided by the sum of the Median Monthly P50 Peak Loads of the Participants being assessed the Load Charge for the Month for which the WRAP Administration Charge is being calculated, times that Participant's Median Monthly P50 Peak Load;

And where:

Base Costs means the Costs for the Month of the Base Services Cost Centers shown in the WRAP Cost Assignment Matrix, plus the Base Services Percentage times the Costs for that Month of the Dual Benefit Cost Centers shown below in Section 4: WRAP Cost Assignment Matrix;

Load Services Costs means the Costs for the Month of the Load Services Cost Centers shown in the WRAP Cost Assignment Matrix, plus the Load Services Percentage times the Costs for that Month of the Dual Benefit Cost Centers shown in the WRAP Cost Assignment Matrix; and

Median Monthly P50 Peak Loads means, for each Participant, the median of the Monthly P50 Peak Loads used in the FS Capacity Requirement of such Participant for two Binding Seasons corresponding to the two FS Submittal most recently validated by WPP.

If before or during a Binding Season, a Participant has need to update their Monthly P50 Peak Load for allowable reasons, those updated Monthly P50 Peak Loads will be replaced and the Median Monthly P50 Peak Load value recalculated upon validation of the change in participating load.

A Participant joining the Program will supply data such that WPP can validate Monthly P50 Peak Loads for the first two Binding Seasons for which the Participant will submit an FS Submittal for use in calculating Load Services Costs until these FS Submittals are submitted and reviewed in the normal timeframe.

Section 3. Maximum Charge Rates

3.1 Notwithstanding anything to the contrary in this Schedule 1, the sum of the Base Charges for all Months in a Year shall not exceed the Annual Maximum Base Charge of $59,000/Year, and the sum of the Load Charge Rates for all Months in a Year shall not exceed the Annual Maximum Load Charge Rate of $199/MW. WPP shall, to the extent reasonably practicable, provide two-months' notice prior to WPP's filing at FERC of an application to change the Maximum Base Charge or the Maximum Load Charge Rate, provided that nothing herein shall limit the Board of Director's authority and discretion to seek at FERC a change in the maximum rates in the time and manner the Board determines in the best interests of the Western Resource Adequacy Program. For purposes of clarity, these specified maximum rates on the Base Charge and the Load Charge do not limit the level of the Cash Working Capital Support Charge established under Section 5 of this Schedule 1, nor do they limit the amount of the default Allocation assessment provided under Part I of this Tariff.

3.2 To facilitate Participant planning, the WPP shall prepare, and provide to the RAPC, good faith, non-binding estimates of: (i) reasonably anticipated WRAP budgets for three Years beyond the most recently approved WRAP budget, including sensitivity analyses for reasonably identified major contingencies; (ii) reasonably anticipated numbers of Participants and MWs of Winter and Summer P50 Loads for each such Year; and (iii) reasonably anticipated highest monthly Base Charges and Load Charge Rates for each such Year. All assumptions and estimates in such forecasts and analyses shall be in WPP's sole discretion, which may be informed by RAPC discussion of such topics.

Section 4. WRAP Cost Assignment Matrix

	BASE COSTS	LOAD COSTS	DUAL BENEFIT
PROGRAM ADMINISTRATION (NON-PARTICIPANT)		100%	
PROGRAM ADMINISTRATION (PARTICIPANT ENGAGEMENT, RAPC FACILITATION)	100%		
WRAP PORTION OF WPP BOD COSTS			50%/50%
PROGRAM OPERATIONS STAFFING AND OVERHEAD		100%	
PROGRAM OPERATIONS TECHNOLOGY		100%	

LEGAL SERVICES	100%
INDEPENDENT EVALUATOR	100%

Section 5. Cash Working Capital Support Charge

5.1 In addition to the WRAP Administration Charge, each Participant shall be assessed a Cash Working Capital Support Charge, to support WPP's maintenance of sufficient funds on hand to make payments required for the operation and administration of the WRAP on a timely basis. Cash Working Capital Support Charges shall be designed to maintain a Cash Working Capital Fund that, at its maximum level over a twelve-month cycle, equals approximately nine-twelfths of the expected annual payment due from the WPP to the Program Operator for its Program Operator services.

5.2 A Participant shall pay a Cash Working Capital Support Charge no later than thirty days after that Participant executes a WRAPA. The Cash Working Capital Support Charge due following WRAPA execution equals the Cash Working Capital Support Charge Rate, calculated as the Cash Working Capital Fund at its required maximum twelve-month cycle level divided by the sum of the Median Monthly P50 Peak Loads of all Participants, times that Participant's Median Monthly P50 Peak Load.

5.3 To the extent the Cash Working Capital Fund is adequately funded at the time a new Participant executes a WRAPA, the revenue from such Participant's payment of the Cash Working Capital Support Charge shall be distributed to all Participants that previously have paid a Cash Working Capital Support Charge, pro rata based on the Median Monthly P50 Peak Loads of all Participants that have previously paid such charge.

5.4 To the extent, and at such time, WPP determines that an incremental addition to the Cash Working Capital Fund is needed due to such causes as, for example, an expected increase in the annual payment to the Program Operator, each Participant shall be assessed an Incremental Cash Working Capital Support Charge equal to the desired incremental addition, divided by the sum of the Median Monthly P50

Peak Loads of all Participants being assessed the Incremental Cash Working Capital Support Charge for the Month for which the Incremental Cash Working Capital Support Charge is being calculated, times that Participant's Median Monthly P50 Peak Load.

ATTACHMENT A

Western Resource Adequacy Program Agreement

This Western Resource Adequacy Program Agreement ("Agreement") dated as of _____ ("Effective Date") is entered into by and between Western Power Pool Corporation ("WPP") and _____ ("Participant"). WPP and Participant are each sometimes referred to in the Agreement as a "Party" and collectively as the "Parties."

In consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties agree as follows:

1. The Parties agree that this agreement shall be governed by the rates, terms, and conditions of the Western Resource Adequacy Program Tariff ("Tariff") and all such rates, terms, and conditions contained therein are expressly incorporated by reference herein. All capitalized terms that are not otherwise defined herein shall have the meanings ascribed by the Tariff.

2. Participant wishes to participate in the Western Resource Adequacy Program ("WRAP") administered by WPP under the Tariff.

3. Participant certifies that it satisfies all of the following qualifications:

    3.1 Participant is a Load Responsible Entity as that term is defined in the Tariff.

    3.2 Participant commits to complying with all applicable terms and conditions of WRAP participation as set forth in the Tariff and Business Practice Manuals adopted thereunder, including all Forward Showing Program and Operations Program requirements.

4. Participant will register all resources and supply contracts and shall disclose any other obligations associated with those resources and supply contracts.

5. Participant represents and warrants that it is authorized by all relevant laws and regulations governing its business to enter into this Agreement and assume all rights and obligations thereunder.

6. It is understood that, in accordance with the Tariff, WPP, as authorized by its independent Board of Directors, may amend the terms and conditions of this Agreement or the Tariff by notifying the Participant in writing and making the appropriate filing with FERC, subject to any limitations on WPP's authority to amend the Tariff as set forth therein.

7. Participant agrees to pay its share of all costs associated with the WRAP, as calculated pursuant to Schedule 1 of the Tariff. The manner and timing of such payment shall be as specified in Schedule 1 of the Tariff.

8. WPP agrees to provide all services as set forth in the Tariff.

9. Term and termination. This Agreement shall commence upon the Effective Date and shall continue in effect until terminated either by WPP by vote of its Board of Directors or by Participant's withdrawal as set forth herein. WPP and Participant agree that participation in the WRAP is voluntary, subject to the terms and conditions of this Agreement and the Tariff. The date upon which a Participant's withdrawal is effective and its participation in the program terminates is referred to as the "Withdrawal Date."

9.1 Normal Withdrawal: In general, Participant may withdraw from this Agreement by providing written notice to WPP no less than twenty-four months prior to commencement of the next binding Forward Showing Program period. Once notice has been properly given, Participant remains in a "Withdrawal Period" until the Withdrawal Date.

9.1.1 During Participant's Withdrawal Period, Participant remains subject to all requirements and obligations imposed by the Tariff and this Agreement, including but not limited to all obligations imposed in the Forward Showing Program and Operations Program and obligation to pay Participant's share of all costs associated with the WRAP.

9.1.2 All financial obligations incurred prior to and during the Withdrawal Period are preserved until satisfied.

9.1.3 During the Withdrawal Period, Participant is not eligible to vote on any actions affecting the WRAP that extend beyond the Withdrawal Period.

9.2 Expedited Withdrawal: Participant may withdraw from this agreement with less than the required twenty-four month notice as set forth below. Participant shall negotiate with WPP regarding the timing of the Expedited Withdrawal.

9.2.1 Extenuating Circumstances: The following such events and circumstances shall constitute "extenuating circumstances" justifying a withdrawal on less than twenty-four months. Participant invoking an extenuating circumstance shall negotiate with WPP regarding potential ways to minimize the impact of the expedited withdrawal on all other Participants and WPP. Such extenuating circumstances and any mitigation plan to minimize the impact of the expedited withdrawal must be reviewed and approved by the Board of Directors prior to termination of Participant's WRAP obligations. Regardless of the extenuating circumstance, all financial obligations incurred prior to the Withdrawal Date remain in effect until satisfied.

9.2.1.1 A governmental authority takes an action that substantially impairs Participant's ability to continue to

participate in the WRAP to the same extent as previously; provided, however, that Participant shall be obligated to negotiate with WPP regarding potential ways to address the impact of the regulatory action without requiring a full withdrawal of Participant from the WRAP if possible.

9.2.1.2 Continued participation in the WRAP conflicts with applicable governing statutes or other applicable legal authorities or orders.

9.2.1.3 Participant voted against a RAPC determination and disagreed with a Board of Directors decision to release composite or aggregated data under Section 10.2.1 of the Tariff, provided that such right to expedited withdrawal is exercised promptly after the first time that the Board of Directors determines that the form and format of composite or aggregated data sufficiently protects against the release of confidential or commercially sensitive Participant data. Failure to exercise this right promptly upon the first occurrence of the Board of Directors voting on a specific form and format of composite or aggregated data shall constitute a waiver of the right to expedited withdrawal for any future disclosures of composite or aggregated data in the same or substantially similar form and format.

9.2.1.4 FERC or a court of competent jurisdiction requires the public disclosure of a Participant's confidential or commercially sensitive information, as further described in Section 10.5 of the Tariff; provided however that such right to expedited withdrawal shall be exercised promptly upon the exhaustion of all legal or administrative remedies aimed at preventing the release.

9.2.2 Exit Fee: If the impact of Participant's withdrawal on WRAP operations can calculated with a high degree of confidence and mitigated by the payment of an "exit fee" to be calculated by WPP, an expedited withdrawal will be permitted. Such exit fee shall include (but not be limited to): (i) any unpaid WRAP fees or charges; (ii) Participant's share of all WRAP administrative costs incurred up to the next Forward Showing Program period; (iii) any costs, expenses, or liabilities incurred by WPP and/or the Program Operator directly resulting from Participant's withdrawal; and (iv) any costs necessary to hold other participants harmless from the voluntary expedited withdrawal. The exit fee may be waived to the extent that it would violate any federal, state, or local statute, regulation, or ordnance or exceed the statutory authority of a federal

agency. The exit fee shall be paid in full prior to the Withdrawal Date.

9.2.3 Amendments to Section 3.4 of the Tariff: In the event that amendments to Section 3.4 of the Tariff are approved by the RAPC and Board of Directors, a Participant that voted against such a change may withdraw with less than the required twenty-four month notice, provided that the Participant satisfy all obligations in the Forward Showing Program and Operations Program and satisfy all other financial obligations incurred prior to the date that the amendments to Section 3.4 of the Tariff are made effective by FERC.

9.2.4 Expulsion: The Board of Directors, in its sole discretion, may terminate Participant's participation in the WRAP and may terminate this Agreement with Participant for cause, including but not limited to material violation of any WPP rules or governing documents or nonpayment of obligations. Prior to exercising such right to terminate, the Board of Directors shall provide notice to Participant of the reasons for such contemplated termination and a reasonable opportunity to cure any deficiencies. Such Board of Directors termination shall be after an affirmative vote consistent with the Board of Directors standard voting procedures. Such termination shall not relieve the Participant of any financial obligations incurred prior to the termination date, and WPP may take all legal actions available to recover any financial obligations from Participant.

10. No Waiver of Non-FERC-Jurisdictional Status. If Participant is not subject to the jurisdiction of FERC as a public utility under the Federal Power Act, Participant shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over Participant that does not otherwise exist. Participant acknowledges that FERC has jurisdiction over the WRAP, including Participant's activities in the WRAP.

[SIGNATURE BLOCKS]

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	)

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

Exhibit 2-148:
WRAP Notice

WESTERN RESOURCE ADEQUACY PROGRAM

WPP Notice to WRAP Resource Adequacy Participants Committee

Oct. 31, 2025, 9:42 a.m. by Rebecca Sexton | Last modified Oct. 31, 2025, 12:54 p.m.

On Friday, October 31, WPP Chief Strategy Officer Rebecca Sexton sent this notice to members of the WRAP Resource Adequacy Participants Committee, regarding participants committed to WRAP binding operations in Winter 2027/2028:

Today is the deadline set in the tariff for Western Resource Adequacy Program (WRAP) participants to notify us if they plan to exit the program before binding operations start in Winter 2027/2028.

As of the deadline there are 16 current participants that will remain in the program for binding operations, including five in addition to the 11 who sent a commitment letter last month, and we expect more companies to join in the future. The committed participants bring significant load (over 58,000 MW in peak load) and resources and a large, diverse geographic footprint, making WRAP one of the largest RA programs in the country and giving us critical mass for a binding program. The group includes members committed to or leaning toward both EDAM and Markets+, as well as some who have not indicated they will join a day-ahead market. The committed participants are:

- Arizona Public Service Company
- Avista Corp
- Bonneville Power Administration
- PUD No. 1 of Chelan County
- Clatskanie People's Utility District
- Constellation
- PUD #2 of Grant County
- Idaho Power
- NorthWestern Energy
- Powerex Corp.
- Puget Sound Energy
- Salt River Project Agricultural Improvement and Power District
- Seattle City Light
- Tacoma Power
- The Energy Authority, Inc.
- Tucson Electric Power

The following companies provided formal notice of intent to exit:

- Calpine Energy Solutions
- Eugene Water & Electric Board
- NV Energy
- PacifiCorp
- Portland General Electric Company
- Public Service Company of New Mexico

To all participants, thank you for your efforts in the last six years to build WRAP into a program that can help the region tackle the significant challenge of resource adequacy.

To our exiting participants, over the next two years, we encourage you to stay engaged in committees, task forces, and the stakeholder process to continue to evolve and improve WRAP and potentially resolve the concerns that prevented you from committing to binding operations at this time. As we have communicated previously, should your concerns be resolved, you have the option to rejoin the program and can commit to the Winter 2027/2028 season as late as September 15, 2026.

We have received a lot of positive outreach and support as we neared this deadline, and I will share just one example - part of a note we received from Lauren Tenney Denison, Director of Market Policy & Grid Strategy for Public Power Council. She wrote, "You have designed a remarkable program, from the ground up. WRAP has forever changed the way the West approaches markets and regional programs. There is a large and diverse footprint of entities committed to the binding season. That is a lot to be excited about."

I wanted you all to see this too because the congratulations for designing this program are for all of us and because there is a lot of progress to be excited about.

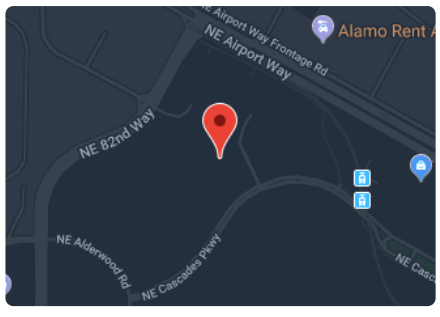
We look forward to continuing to work collaboratively to support reliability and resource adequacy across the West.



Rebecca Sexton
Chief Strategy Officer
WPP | 253-279-3002
rebecca.sexton@westernpo...

WPP HEADQUARTERS

7525 NE Ambassador Place, Suite M
Portland, Oregon, 97220
(503) 445-1074



PROGRAMS
NEWS
EVENTS
DOCUMENTS
ABOUT
SIGN IN

WESTERN POWERPOOL

CONTACT

© 2026 WPP | All rights reserved. | Terms of Use | Anti-trust Compliance

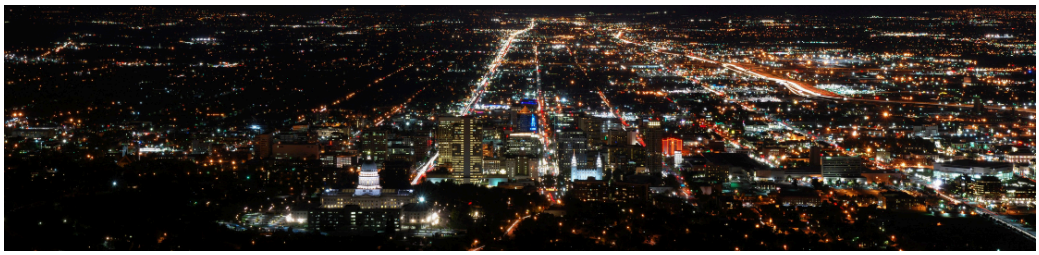
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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	)

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

Exhibit 2-149:
About WECC webpage

LOGIN



About WECC

The Western Electricity Coordinating Council (WECC) is a non-profit corporation that exists to ensure a reliable Bulk Electric System in the geographic area known as the Western Interconnection. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.



WECC promotes bulk power system reliability and security in the Western Interconnection. WECC is the Regional Entity responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC Bylaws.

There are six Regional Entities given authority by NERC and FERC. Of those six entities, WECC oversees the largest and most geographically diverse region, known as the Western Interconnection. WECC's footprint

extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.

Membership in WECC is open to all entities that meet the qualifications in the WECC Bylaws. WECC strives for transparency and open participation in all of its meetings and processes.

2024 State of the Interconnection Report

Our History

@ 2026 WECC

LEGAL

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	)

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

Exhibit 2-150:
NERC Rules of Procedure

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: November 28, 2023

TABLE OF CONTENTS

SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE 1

SECTION 200 — DEFINITIONS OF TERMS 2

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT 3

301. General 3
302. Essential Attributes for Technically Excellent Reliability Standards 3
303. Relationship between Reliability Standards and Competition 5
304. Essential Principles for the Development of Reliability Standards 5
305. Registered Ballot Body 6
306. Standards Committee 7
307. Standards Process Management 8
308. Steps in the Development of Reliability Standards 8
309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities 9
310. Annual Reliability Standards Development Plan 10
311. Regional Entity Standards Development Procedures 10
312. Regional Reliability Standards 12
313. Other Regional Criteria, Guides, Procedures, Agreements, Etc. 15
314. Conflicts with Statutes, Regulations, and Orders 15
315. Revisions to NERC Standard Processes Manual 16
316. Reserved 16
317. Periodic Review of Reliability Standards 16
318. Coordination with the North American Energy Standards Board 16
319. Archived Standards Information 16
320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels 16
321. Special Rule to Address Certain Regulatory and Board of Trustees Directives 17
322. Special Authority to Address Reliability Matters Necessary to Maintain the Reliability of the Bulk Power System 21

SECTION 400 — COMPLIANCE MONITORING AND ENFORCEMENT 24

401. Scope of the Compliance Monitoring and Enforcement Program 24
402. NERC Oversight of the Compliance Monitoring and Enforcement Program 26
403. Required Attributes of Regional Entity Implementation of the Compliance Monitoring and Enforcement Program 29
404. NERC Monitoring of Compliance for Bulk Power System Owners, Operators, or Users 35
405. Monitoring NERC's Compliance with the Rules of Procedure 36
406. Independent Audits of the Compliance Monitoring and Enforcement Program 36
407. Penalties, Sanctions, and Remedial Action Directives 37
408. Review of NERC Decisions 37
409. Appeals from Final Decisions of Hearing Bodies 39
410. Hold Harmless 40
411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards 40
412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee 40
413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed 41
414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings 41

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION 44

501. Scope of the Organization Registration and Organization Certification Programs 44
502. Organization Registration and Organization Certification Program Requirements 48
503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements 50
504. Appeals 51
505. Program Maintenance 51
506. Independent Audit of NERC Organization Registration and Organization Certification Program 51
507. Provisions Relating to Joint Registration Organizations (JRO) 52
508. Provisions Relating to Coordinated Functional Registration (CFR) Entities 53
509. Exceptions to the Definition of the Bulk Electric System 55

SECTION 600 — PERSONNEL CERTIFICATION AND CREDENTIAL MAINTENANCE PROGRAM 56

601. Scope of Personnel Certification and Credential Maintenance Program 56
602. Structure of ERO Personnel Certification and Credential Maintenance Program 56
603. Examination and Maintenance of NERC System Operator Certification Credentials 57
604. Dispute Resolution Process 58
605. Disciplinary Action 59
606. Candidate Testing 61
607. Public Information About the Personnel Certification Program 62
608. Responsibilities to Applicants for Certification or Re-Certification 62
609. Responsibilities to Employers of Certified Personnel 63
610. [PLACEHOLDER] 63

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS 64

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members 64
702. Formation of Sector Forum 64

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS 65

801. Objectives of the Reliability Assessment and Performance Analysis Program 65
802. Scope of the Reliability Assessment Program 65
803. Reliability Assessment Reports 66
804. Reliability Assessment Data and Information Requirements 67
805. Reliability Assessment Process 68
806. Scope of the Reliability Performance and Analysis Program 70
807. Analysis of Major Events 70
808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities 71
809. Reliability Benchmarking 72
810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions 72
811. Equipment Performance Data 73

SECTION 900 — TRAINING AND EDUCATION 74

901. Scope of the Training and Education Program 74
902. [PLACEHOLDER] 74

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY 75

1001. Situation Awareness 75
1002. Reliability Support Services 75
1003. Infrastructure Security Program 76

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS 79

1101. Scope of Business Plans and Budgets 79
1102. NERC Funding and Cost Allocation 79
1103. NERC Budget Development 79
1104. Submittal of Regional Entity Budgets to NERC 80
1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval 80
1106. NERC and Regional Entity Billing and Collections 81
1107. Penalty Applications 82
1108. Special Assessments 83

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS 84

1201. Pro Forma Regional Delegation Agreement 84
1202. Regional Entity Essential Requirements 84
1203. Negotiation of Regional Delegation Agreements 84
1204. Conformance to Rules and Terms of Regional Delegation Agreements 84
1205. Sub-delegation 84
1206. Nonconformance to Rules or Terms of Regional Delegation Agreement 84
1207. Regional Entity Audits 85
1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity .. 85

SECTION 1300 — COMMITTEES 88

1301. Establishing Standing Committees 88
1302. Committee Membership 88
1303. Procedures for Appointing Committee Members 88
1304. Procedures for Conduct of Committee Business 88
1305. Committee Subgroups 89

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE 90

1401. Proposals for Amendment or Repeal of Rules of Procedure 90
1402. Approval of Amendment or Repeal of Rules of Procedure 90

SECTION 1500 — CONFIDENTIAL INFORMATION 91

1501. Definitions 91
1502. Protection of Confidential Information 91
1503. Requests for Information 92
1504. Employees, Contractors and Agents 94
1505. Provision of Information to FERC and Other Governmental Authorities 94
1506. Permitted Disclosures 94
1507. Remedies for Improper Disclosure 95

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION 96

1601. Scope of a NERC or Regional Entity Request for Data or Information 96
1602. Procedure for Authorizing a NERC Request for Data or Information 96
1603. Owners, Operators, and Users to Comply 97
1604. Requests by Regional Entity for Data or Information 97
1605. Confidentiality 98
1606. Expedited Procedures for Requesting Time-Sensitive Data or Information 98

SECTION 1700 — CHALLENGES TO DETERMINATIONS 100

1701. Scope of Authority 100
1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023 100
1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509 102

SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted.[1] Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

    2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

    2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

[1] When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments or revisions to the NERC *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

    3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in

each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment at any time or apply to change Segments as described in the *Development of the Registered Ballot Body* in **Appendix 3D**. In the event a change in corporate or organizational structure results in merged or affiliated entities having more than one membership in a particular Segment, the merged or affiliated entities shall withdraw the additional memberships before joining any new ballot pools or voting on any standards action as part of an existing ballot pool.

3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments periodically to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the

Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC standards staff shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual* and shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. NERC staff shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The NERC *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the NERC *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or

is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop New or Modified Reliability Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC, NERC shall within five (5) business days notify all other Applicable Governmental Authorities. Reliability Standards that are directed by an Applicable Governmental Authority shall be developed using the NERC *Standard Processes Manual*. The waiver provisions of the NERC *Standard Processes Manual* may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authority, respecting to the extent possible the provisions in the *NERC Standard Processes Manual* for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the standards process did not result in a Reliability Standard that adequately addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the waiver provisions of the NERC *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests

in developing Reliability Standards. If the Board of Trustees determines that the standards process did not result in a Reliability Standard that adequately addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

    3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard, due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional

Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

   3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall

rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or

is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted

by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or regional Variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — Each Regional Entity that has Regional Criteria shall maintain a publicly-available, current catalog of its Regional Criteria. Regional Entities shall provide any Regional Criteria to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and

propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Reserved

317. Periodic Review of Reliability Standards

NERC shall complete a periodic review of each NERC Reliability Standard in accordance with the NERC *Standard Processes Manual*. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by NERC staff of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the Standard Processes Manual, Appendix 3A to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory and Board of Trustees Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps; provided that the Board of Trustees shall, to the extent feasible and consistent with its obligations and established deadlines, choose actions that seek to maximize stakeholder participation.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities or by the NERC Board of Trustees pursuant to its authority in Section 322. If the Board of Trustees is presented with a proposed Reliability Standard that fails to adequately address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority or by the NERC Board of Trustees pursuant to its

authority in Section 322, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory or Board directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; (iii) use the input from the technical conference to revise the proposed Reliability Standard, as appropriate; and (iv) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory or Board directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective. In addition, the Board of Trustees may direct further revisions in accordance with Rule 322.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to take one of the following actions:

4.3.2.1 For a regulatory directive, the Board of Trustees may treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

4.3.2.2 For a Board directive, the Board of Trustees may remand the proposed Reliability Standard and direct further work under this Section.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority or the Board of Trustees, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory or Board directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of

Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective. In addition, the Board of Trustees may direct further work in accordance with Rule 322.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to take one of the following actions:

5.3.1 For a regulatory directive, the Board of Trustees may direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.3.2 For a Board directive, the Board of Trustees may remand the proposed Reliability Standard and direct further work under this Section.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

322. Special Authority to Address Reliability Matters Necessary to Maintain the Reliability of the Bulk Power System

To meet NERC's statutory responsibility under Section 215 of the Federal Power Act to develop Reliability Standards that provide for an adequate level of reliability for the Bulk Power System, the Board of Trustees shall have the authority to direct the development of a new or revised Reliability Standard. The Board of Trustees will only exercise this authority in extraordinary circumstances, where the Board determines a directive is essential to provide for an adequate level of reliability for the Bulk Power System consistent with Section 215 of the Federal Power Act. This authority shall be in addition to the Board of Trustees' other authorities regarding Reliability Standards as provided in these Rules of Procedure and the Bylaws. In issuing such directives, the following process shall be used:

1. The Board of Trustees shall provide public notice of its intent to direct the development of a new or revised Reliability Standard to address a matter it has deemed essential to provide for an adequate level of reliability for the Bulk Power System. This notice shall take the form of a written document that includes, at a minimum, the following:

    1.1 the proposed date for issuing the proposed directive, which shall be no earlier than 60 days from the date of the notice, and the period for public comment, which shall be no less than 45 days;

    1.2 a description of the proposed directive, including any deadlines for standards development;

    1.3 the reliability basis for the proposed directive;

    1.4 the reasons why the Board has preliminarily determined that extraordinary circumstances exist, and that the proposed directive is essential to assure the reliable operation of the Bulk Power System;

    1.5 identification of any past, current, or planned stakeholder-initiated standards development projects to address the reliability matter addressed by the proposed directive; and

    1.6 An explanation of why the Board has preliminarily determined that the reliability matter cannot be addressed adequately or in a timely manner through stakeholder-initiated projects or a project initiated by NERC Staff.

2. NERC shall publicly post the notice and set a public comment period for the time described in the notice.

3. The Board of Trustees may direct the development of a new or revised Reliability Standard, as originally proposed or with modifications, if it determines that such action is just, reasonable, not unduly discriminatory, and in the public interest. This action shall take the take the form of a written determination containing, at a minimum, the following:

    1.1 the effective date of the directive;

    1.2 a description of the directive, including any deadlines for standards development;

    1.3 the reliability basis for the directive;

    1.4 the reasons why the Board has determined that extraordinary circumstances exist, and that the directive is essential to assure the reliable operation of the Bulk Power System;

    1.5 identification of any past, current, or planned stakeholder-initiated standards development projects to address the reliability matter addressed by the proposed directive;

    1.6 An explanation of why the Board has determined that the reliability matter cannot be addressed adequately or in a timely manner through stakeholder-initiated projects or a project initiated by NERC Staff; and

    1.7 a description of how the Board of Trustees considered any advice provided by the Member Representatives Committee, or any comments provided by the public, NERC standing committees, Applicable Governmental Authorities or other regulatory authorities, the Regional Entities, or NERC management.

4. Any person or entity with directly and materially affected interests in the subject of a Board of Trustees directive, including any nonprofit association representing members with such interests, may request the Board of Trustees reconsider or clarify its determination. Such request shall be submitted in writing within 30 calendar days of the issuance of the determination and contain, at a minimum, a description of the matter for which the entity is seeking reconsideration or clarification, the reasons therefor, and the interests that would be affected if the requested reconsideration or clarification is not granted. If the Board of Trustees does not act on the request within 30 days, it may be deemed denied. Unless

otherwise directed by the Board of Trustees, no deadline for action shall be stayed pending the disposition of any request for reconsideration or clarification.

5. NERC shall publicly post all Board of Trustees directives and any supporting documentation. This information shall become part of the record of development for the resulting Reliability Standard.

6. Where the Board of Trustees has determined to direct the development of a new or revised Reliability Standard, NERC Staff shall prepare a Standards Authorization Request for submission to the Standards Committee.

7. Reliability Standards that are directed by the Board of Trustees shall be developed using the NERC Standard Processes Manual. The waiver provisions of the NERC *Standard Processes Manual* may be applied if necessary to meet a timetable for action required by the Board of Trustees, respecting to the extent possible the provisions in the *NERC Standard Processes Manual* for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in its directive, then the Board of Trustees may, in its discretion, apply Rule 321 of these Rules of Procedure.

SECTION 400 — COMPLIANCE MONITORING AND ENFORCEMENT

401. Scope of the Compliance Monitoring and Enforcement Program

1. **Components of the Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a Compliance Monitoring and Enforcement Program (CMEP) to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North America in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC or other legal instrument approved by an Applicable Governmental Authority) has been given enforcement authority.

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users are required to comply with all approved Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC or the Compliance Enforcement Authority (CEA) such Documents, data, and information as is necessary to monitor and enforce compliance with the Reliability Standards. NERC and the CEA will define the data retention and reporting requirements.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer the CMEP provided in these Rules of Procedure.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity if NERC does not have a delegation agreement with a Regional Entity, the Regional Entity or NERC terminates the delegation agreement, or the Regional Entity does not administer the CMEP in accordance with the delegation agreement or other applicable requirements.

   5.1 In the circumstances outlined above, the following will apply:

      1. This monitoring and enforcement can be coordinated with staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant information regarding Registered Entities in the geographic footprint or for which the Regional Entity has CMEP responsibilities under coordinated oversight of Registered Entities, as specified in a termination agreement.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies consistent with Section 1107 of the Rules of Procedure.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the CMEP within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Risk Elements** — NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify ERO and Regional Entity-specific risk elements, together with related Reliability Standards and Requirements are to be considered to prioritize CMEP activities. NERC coordinates with the Regional Entities to identify the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable Reliability Standards whether or not they are identified as areas of focus to be considered for compliance oversight in the annual ERO CMEP Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which are incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC and Regional Entities shall coordinate to maintain a record of each compliance submission, including potential noncompliance with approved

Reliability Standards; associated Penalties, sanctions, Remedial Action Directives, and settlements; and the status of Mitigating Activities.

10. **Confidential Information** — The types of CMEP information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500.

    The disclosure by the CEA or NERC of any CMEP Confidential Information shall follow Section 1500.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with the resolution of a potential noncompliance with a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a potential noncompliance or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC shall, subject to the requirements, rules, and regulations of the Applicable Governmental Authority and the confidentiality requirements of these Rules of Procedure, publicly post information on each such noncompliance, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation, on its website. As required by an Applicable Governmental Authority, NERC will also post information concerning noncompliance disposed of as Compliance Exceptions, subject to Section 1500 of these Rules of Procedure.

    11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the publicly posted information. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

    11.2 Subject to the disclosure requirements of the Applicable Governmental Authority and redaction of Critical Energy Infrastructure Information, Critical Electric Infrastructure Information, or other Confidential Information, for each resolved noncompliance submitted to the Applicable Governmental Authority, the public posting shall include: a) the name of any relevant entity, b) the nature, time period, and circumstances of the noncompliance, c) any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity, and d) sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Review of Noncompliance** — NERC staff shall periodically review and analyze reports of noncompliance to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Compliance Monitoring and Enforcement Program

1. **Oversight** — NERC shall oversee each Regional Entity that has been delegated authority. The objective of this oversight is to ensure that the Regional Entity

carries out its obligations under the CMEP in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's execution of the CMEP. Oversight by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, regular evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance metrics, risk-based monitoring activities, and performance reports. Through this oversight, NERC evaluates the Regional Entity's effectiveness and implementation of the CMEP using, among other things, the criteria developed by the NERC Compliance and Certification Committee.

1.1 **Annual ERO CMEP Implementation Plan** — NERC and the Regional Entities will maintain and update an ERO CMEP Implementation Plan. The ERO CMEP Implementation Plan reflects ERO and Regional Entity-specific risk elements that CEAs should prioritize for oversight of Registered Entities.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity implements the CMEP. The audit shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreements, directives in effect pursuant to the delegation agreements, the approved annual ERO CMEP Implementation Plan, required CMEP attributes, and NERC CMEP guidance and procedures. The audit shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 4.1.4 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to

verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's implementation of the CMEP.

2. **Consistency in Regional Implementation of the Compliance Monitoring and Enforcement Program** — To provide for consistency and fairness of the processes used for Regional Entity findings of compliance and noncompliance and the application of Penalties and sanctions for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single CMEP, which is incorporated into these Rules of Procedure as **Appendix 4C**. Any differences in CMEP methods, including determination of noncompliance and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall periodically conduct Regional Entity CMEP manager meetings. These meetings shall identify and resolve CMEP differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Noncompliance Disclosure** — NERC shall follow the process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — The CEA shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Remedial Action Directives may be issued by a CEA that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert noncompliance with a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections

408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

7. **Conflict Disclosure** — NERC shall disclose to the Applicable Governmental Authority any potential conflicts between a market rule and the enforcement of a Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the CMEP, NERC and Regional Entities, Compliance Audit team members, and committee members shall maintain the confidentiality of information obtained and shared during CMEP activities.

    8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for all participants in CMEP activities.

    8.2 A participant's failure to follow the code of conduct or Confidential Information provisions of these Rules of Procedure may result in that person and any member organization with which the person is associated losing access to Confidential Information on a temporary or permanent basis and being subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future CMEP activities. Nothing in Section 1500 precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to participants in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Implementation of the Compliance Monitoring and Enforcement Program

Each Regional Entity shall (i) conform to and comply with the CMEP, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its CMEP activities shall exhibit independence, meaning the Regional Entity shall be organized so that its CMEP activities are carried out separately from other activities of the Regional

Entity. The CMEP activities shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity shall exercise the responsibility and authority in carrying out the delegated functions of the CMEP in accordance with delegation agreements and **Appendix 4C**.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the CMEP, a Regional Entity shall not sub-delegate its CMEP duties to entities or persons other than the Regional Entity Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** Unless the Regional Entity has elected to participate in the Consolidated Hearing Process, the Regional Entity board or compliance panel reporting directly to the Regional Entity board will designate a Hearing Body (with appropriate recusal procedures) that will be vested with the authority for conducting all compliance hearings, pursuant to the hearing process selected under Section 403.15, in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single sector may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the CMEP.

6. **Regional Entity Staff Independence** — The Regional Entity Staff, collectively, shall be capable and required to: a) make all determinations of compliance and noncompliance; b) determine Penalties, sanctions, and Remedial Action Directives; and c) review and accept Mitigation Plans and other Mitigating Activities.

    6.1 Regional Entity Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

6.2 Regional Entity Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes, make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

6.3 Regional Entity Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

6.4 Regional Entity Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure and the delegation agreement

6.5 Contracting with independent consultants or others working for the Regional Entity shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals shall be considered as augmenting Regional Entity Staff under these Rules of Procedure.

7. **Use of Industry Subject Matter Experts and Regional Entity Members** — Industry experts and Regional Entity members may be called upon to provide their technical expertise in CMEP activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than Regional Entity staff. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized

so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Antitrust Provisions** — Each Regional Entity's CMEP activities shall be structured and administered to abide by United States antitrust law and Canadian competition law.

9. **Information Submittal** — All Bulk Power System owners, operators, and users responsible for complying with Reliability Standards within the Regional Entity shall submit timely and accurate Documents, data, and information when requested by the Regional Entity or NERC. Where appropriate, Submitting Entities should comply with the requirements of Section 1500 in submitting such Documents, data, and information. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

9.1 Each Regional Entity has the authority to collect the necessary Documents, data, and information to determine compliance and shall develop processes for gathering Documents, data, and information from the Bulk Power System owners, operators, and users the Regional Entity monitors.

9.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.9 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

9.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

9.4 Regional Entities shall notify NERC of noncompliance with Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

9.5 As requested by the CEA, a Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan or conduct Mitigating Activities in accordance with **Appendix 4C**. The Regional Entity Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

9.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all Self-Reports to the Regional Entity, including Documents, data, and information provided with the Self-Report.

9.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

10. **Compliance Monitoring of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program for risk-based compliance monitoring, to include Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**.

10.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years.

11. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and Documents, data, and information obtained from such processes, are to be non-public and treated in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity, or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as such disclosures are in accordance with Section 1500 and Appendix 4C of these Rules of Procedure.

12. **Critical Energy Infrastructure Information and Critical Electric Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will

be identified and protected from public disclosure as Confidential Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information or Critical Electric Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

13. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties, and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

14. **Hearing Process** — Each Regional Entity shall adopt either the Regional Entity Hearing Process (Section 403.15A) or the Consolidated Hearing Process (403.15B) and conduct all hearings pursuant to the selected process. In either case, the selected hearing process shall be a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single sector may veto any matter brought before the Hearing Body after recusals.

    A Regional Entity may modify its selection of hearing process by giving notice to NERC six (6) months prior to such modification becoming effective. Hearings will be conducted pursuant to the process in effect at the Regional Entity at the time of the submission of the hearing request by the registered entity.

    Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

    If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity Hearing Process or the Consolidated Hearing Process and desires to appeal the outcome of the hearing, the Bulk Power System

owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

14A. **Regional Entity Hearing Process** — The Regional Entity Hearing Process shall be conducted before a Hearing Body composed of the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions.

14B. **Consolidated Hearing Process** — The Consolidated Hearing Process shall be conducted before a Hearing Body composed of five members, unless a smaller number is necessary, as discussed below. The Hearing Body will issue a final decision, provided that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. Up to two members will be appointed by the Regional Entity from which the case originates. If stakeholder members are appointed, the stakeholders shall not represent the same industry sector. Should a Regional Entity choose to appoint one or no representative, then the NERC Board of Trustees Compliance Committee ("Compliance Committee") will select additional representatives to fill those vacancies. The Compliance Committee will appoint the NERC representatives to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing. The Regional Entity and NERC members appointed to the Hearing Body will appoint an additional member to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing or from the Regional Entity from which the case originates. If the Hearing Body does not select a NERC trustee or a regional representative, the Hearing Body will appoint an additional member in accordance with the criteria specified in Appendix 4C, Attachment 2, Section 1.4.3(a). In the event a Regional Entity chooses not to appoint representatives to the Hearing Body and there are not five NERC trustees available to participate on the Hearing Body, as determined by the Compliance Committee, the Hearing Body may be composed of three members (three NERC trustees not serving on the Compliance Committee). The Hearing Body will appoint a Hearing Officer to preside over the hearing.

404. NERC Monitoring of Compliance for Bulk Power System Owners, Operators, or Users

1. **NERC Obligations** —NERC will directly monitor Bulk Power System owners, operators, and users for compliance with Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the CEA described in **Appendix 4C**. Compliance matters contested by Bulk Power

System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Appeals Process** — Any Bulk Power System owner, operator or user found by NERC to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring NERC's Compliance with the Rules of Procedure

The Compliance and Certification Committee shall monitor NERC's compliance with its Rules of Procedure for the Reliability Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs in accordance with this section and Section 506. The Compliance and Certification Committee's monitoring shall not be used to circumvent the appeals processes established for those programs. The Compliance and Certification Committee shall use independent expert monitors with no conflict of interest, real or perceived. Compliance and Certification Committee findings shall be addressed with the NERC Board of Trustees and other appropriate Board committees.

406. Independent Audits of the Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of the Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the NERC Board of Trustees in coordination with the Compliance and Certification Committee. The audit shall be conducted by independent expert auditors as selected by the NERC Board of Trustees. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board of Trustees.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entities in implementing the Compliance Monitoring and Enforcement Program and the effectiveness of the program in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with Appendix 4C.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the Compliance Monitoring and Enforcement Program, the administrators of the Compliance Monitoring and Enforcement Program shall provide a written response and plan to the NERC Board of Trustees within 30 days of the release of the final audit report to the NERC Board of Trustees or other appropriate Board committee. NERC will post the written response and plan for public viewing when authorized by the NERC Board of Trustees or other

appropriate Board committee. NERC will post the written response and plan for public viewing.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions, and Remedial Action Directives that are specified by a Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination: a) is supported by a sufficient record compiled by the Regional Entity; b) is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance, and directions issued by NERC pursuant to the delegation agreement; and c) is consistent with Penalties, sanctions, and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction, or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a Notice of Penalty and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity audit finding, may do so by filing a notice of the challenge with NERC's Director of Enforcement no later than 30 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 30 days after receiving a copy of the notice of challenge, the NERC

Director of Enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — For matters subject to its review, the Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's Director of Enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, NERC may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Board of Trustees Compliance Committee shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Board of Trustees Compliance Committee may invite representatives of the Regional Entity or Registered Entity and the NERC Compliance Monitoring and Enforcement Program to appear before the Board of Trustees Compliance Committee. Decisions of the Board of Trustees Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the CEA, or an owner, operator, or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's Director of Enforcement, with copies to the Clerk, the Regional Entity, and any other Participants in the Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Hearing Body. The Board of Trustees Compliance Committee shall render its decision within 180 days following the receipt by NERC's Director of Enforcement of the notice of appeal. The Board of Trustees Compliance Committee may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Clerk shall file the entire record of the Hearing Body proceeding with NERC's Director of Enforcement, with a copy to all Participants. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The party filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Board of Trustees Compliance Committee shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Hearing Body, the responses, and any reply filed with NERC. The Board of Trustees Compliance Committee shall review the appealed issue(s) under a *de novo* standard. At its discretion, the Board of Trustees Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Hearing Body to appear before the Board of Trustees Compliance Committee. Decisions of the Board of Trustees Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Hearing Body granting or denying a motion to intervene in the Hearing Body proceeding. Appeals of decisions of Hearing Bodies granting or denying motions to intervene in Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of: a) any action or inaction; b) any agreement reached in resolution of the dispute; or c) any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement. The request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees Compliance Committee, for decision, a significant question of law, policy, or procedure, the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Board of Trustees Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Hearing Body to the Board of Trustees Compliance Committee shall be considered and disposed of by the Board of Trustees Compliance Committee.

2. The Board of Trustees Compliance Committee may accept or reject a certification of a question for decision. If the Board of Trustees Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Board of Trustees Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Board of Trustees Compliance Committee. The Board of Trustees Compliance Committee may also request, or provide an opportunity for, the NERC Compliance department, the NERC Enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda are filed in accordance with the schedule, the Board of Trustees Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Board of Trustees Compliance Committee's written decision on the certified question, the Hearing Body shall proceed to complete the hearing in accordance with the Board of Trustees Compliance Committee's decision.

5. The Board of Trustees Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9, and 6.5 of Appendix 4C.

414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Hearing Body proceeding, and the Regional Entity Staff or any other Participant in the Hearing Body proceeding may appeal a decision of the Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Hearing Body proceeding, in either case by filing a notice of appeal with the NERC Director of Enforcement, with copies to the Clerk of the Hearing Body, the Hearing Body, the Hearing Officer, the Regional Entity Staff, and all other Participants in the Hearing Body proceeding,

no later than seven (7) days following the date of the Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Clerk shall transmit to the NERC Director of Enforcement copies of all pleadings filed in the Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Hearing Body, the Regional Entity Staff, and any other Participants in the Hearing Body proceeding, may each file a response to the notice of appeal with the NERC Director of Enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC Director of Enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Board of Trustees Compliance Committee. The NERC Director of Enforcement shall provide copies of the notice of appeal and any responses and replies to the Board of Trustees Compliance Committee. The Board of Trustees Compliance Committee shall issue a written decision on the appeal; provided, that if the Board of Trustees Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Hearing Body granting or denying the motion to intervene shall stand. The NERC Director of Enforcement shall transmit copies of the Board of Trustees Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Board of Trustees Compliance Committee, to the Clerk, the Hearing Body, the entity filing the notice of appeal, the Regional Entity Staff, and any other Participants in the Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Board of Trustees Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Board of Trustees Compliance Committee on an appeal of a Hearing Body decision granting or denying a motion to intervene in a Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Board of Trustees Compliance Committee to FERC

or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules, and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules, or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) Entities may address registration obligations for applicable function types using a Joint Registration Organization (JRO), in lieu of each of the JRO's parties'entities being registered individually for one or more functions. Refer to Section 507.

   (c) Entities may each register using a Coordinated Functional Registration

(CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability

Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. The NERC programs shall:

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

2.1 Evaluate the entity's tools, personnel, facilities, and processes used to perform the duties and tasks identified in and required by the Reliability Standards. The entities currently requiring Certification include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Certify each applicant's ability to perform the function for a specified Area.[3]

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements,

[3] When the term "Area" is used and capitalized it is being used in the certification context, and is inclusive of terms currently defined in NERC Glossary of Terms and Appendix 2 of the ROP, specifically, "Balancing Authority Area," "Reliability Coordinator Area," or "Transmission Operator Area."

and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections VI and VII, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with its members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

   2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

   3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

   3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

   3.3 Regional Entities shall notify NERC of all Certification applicants.

   3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

   3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

      3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing

Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be provided to the NERC Board of Trustees or its appropriate committees, and posted for public viewing. Confidential Information shall be handled in accordance with the NERC Rules of Procedure Section 1500, *Confidential Information*.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all function type(s) that it performs itself, an entity may execute an agreement to register as a Lead Entity of a JRO on behalf of one or more parties to the agreement for one or more function type(s) for which such parties would otherwise be required to register. The Lead Entity thereby, accept on behalf of such parties all compliance responsibility for the function types(s) covered by the JRO registration, including all reporting requirements. The Lead Entity of a JRO must execute a written agreement with the parties on whose behalf it registers that: (1) governs the relationship between the parties; (2) addresses the function type(s) described within Appendix 5B for which the Lead Entity is registering for and taking responsibility, and which would otherwise be the responsibility of one or more of the other parties to the JRO; (3) identifies which entity is the Lead Entity and a point of contact within the Lead Entity; and (4) identifies a point of contact for each of the parties to the JRO.

2. For every JRO, the written agreement must be submitted to the appropriate Regional Entity for its retention. Neither NERC nor the Regional Entity shall be parties to any such agreement. Neither NERC nor the Regional Entity shall have responsibility for reviewing or approving any such agreement, other than to verify that the agreement addresses the function type(s) consistent with the Lead Entity's Registration.

3. The JRO Registration data must include all Registration and Certification information as needed by the Regional Entity to complete the Registration process and to perform assessments of compliance. All Compliance Monitoring and Enforcement related communications shall be directed to the primary compliance contact identified for the Lead Entity of the JRO.[4]

4. The Regional Entity shall notify NERC when it registers a Lead Entity of a JRO. The notification will identify the point of contact and the function type(s) for which the Lead Entity of the JRO is registered on behalf of the JRO parties and a point of contact for each of the JRO parties.

[4] The primary compliance contact for the Lead Entity of a JRO can be the same person who serves as the point of contact for the Lead Entity of the JRO. However, it is not required that the same person serve as both the primary compliance contact and the point of contact.

5. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs, the Lead Entities, the JRO parties,es and the function type(s) for which the Lead Entity of the JRO has registered for each partythat. It is the responsibility of the Lead Entity of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

6. The Regional Entity can request clarification of any list submitted to it that identifies the parties to the JRO and can request such additional information as the Regional Entity deems appropriate.

7. The Regional Entity's acceptance of a Lead Entity's registration as part of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded that the registration of the Lead Entity of the JRO meets the Registration requirements of Section 501(1.4).

8. NERC shall maintain, and post on its website, a listing of all JROs, Lead Entities, JRO parties, and the function type(s) for which the Lead Entity of the JRO has registered for each party.

9. The Lead Entity of the JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

10. Nothing in Section 507 shall preclude any party to a JRO from registering on its own behalf and undertaking full compliance responsibility for the function type(s) for which the Lead Entity of the JRO has registered. Such registration shall include submission of data or information that includes any documentation that the agreement supporting the JRO has been terminated as to the registering party. In addition to any notification requirements contained within the written agreement, a JRO party, that registers as responsible for any function type(s) for which the Lead Entity of a JRO was previously responsible shall inform the Lead Entity of the JRO and/or other parties once its Registration has been accepted by the Regional Entity.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities using a CFR must register for the function associated with the CFR. The CFR submission to the Regional Entity must include a written agreement that: (1) governs itself; (2) specifies the entities' respective compliance responsibilities; (3) identifies which entity is the Lead Entity, a point of contact within the Lead Entity, and a point of contact for each of the parties to the CFR The Lead Entity identified for each CFR is responsible for providing the written agreement between the parties, including submitting updates for currently active CFRs to the Regional Entity related to the CFR Registration; and (4) lists one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function type.

2. Neither NERC nor the Regional Entity shall be parties to any such agreement. Neither NERC nor the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the function type for which the parties are registered and the responsibility(ies) which are addressed through the CFR.

3. The CFR Registration data must include all Registration and Certification information and data, as needed by the Regional Entity to complete the Registration process and to perform assessments of compliance, as it relates to the CFR. All Compliance Monitoring and Enforcement related communications shall be directed to the primary compliance contact(s) identified for each of the CFR parties.

4. Each party to a CFR shall have compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements for which it has registered pursuant to the CFR.

5. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts, and the notification shall include identification of the Lead Entity of a CFR, the function type that the CFR addresses, a point of contact for each of the CFR parties, and any updates to currently active CFRs.

6. For purposes of Compliance Audits, the Regional Entity shall keep a list of all CFRs, the Lead Entities, the CFR parties, the function type that the CFR addresses, and the responsibilities assigned to each of the CFR parties.

7. The Regional Entity can request clarification of any list submitted to it that identifies the parties to the CFR and can request such additional information as the Regional Entity deems appropriate.

8. The Regional Entity's acceptance of a Lead Entity's registration as part of a CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded that the registration of the CFR meets the Registration requirements of Section 501(1.4).

9. NERC shall maintain, and post on its website, a listing of all CFRs, the Lead Entity of CFRs, CFR parties, the function type that the CFR addresses, and the responsibilities assigned to each of the CFR parties. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

10. Any noncompliance shall be investigated in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*.

11. Nothing in Section 508 shall preclude a party to a CFR from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards to which a CFR is applicable. Such

registration shall include submission of data or information that includes any documentation that the agreement supporting the CFR has been terminated or revised as to the Reliability Standards for which the registering party is now taking compliance responsibility. In addition to any notification requirements contained within the written agreement, an entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the Lead Entity of the CFR and/or other parties once its Registration has been accepted by the Regional Entity.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION AND CREDENTIAL MAINTENANCE PROGRAM

601. Scope of Personnel Certification and Credential Maintenance Program

Maintaining the reliability of the Bulk Power System through implementation of the Reliability Standards requires skilled, and qualified personnel, including system operators. NERC shall develop a Personnel Certification and Credential Maintenance Program to:

1. provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. administer a system operator Certification exam;

3. award the system operator Certification Credential to individuals who pass the exam; and,

4. prescribe requirements for System Operators to maintain their Certification Credential.

The NERC Personnel Certification and Credential Maintenance Program shall be international in scope consistent with the ERO's international regulatory responsibility for the reliability of the Bulk Power System in North America.

NERC Reliability Standards define which system operators require certification pursuant to the NERC Personnel Certification Program.

The NERC Personnel Certification Governance Committee (PCGC) is the governing body that both establishes the policies, sets fees, and monitors the performance of the Personnel Certification and Credential Maintenance Program for system operators.

602. Structure of ERO Personnel Certification and Credential Maintenance Program

1. PCGC shall develop a system operator program manual, approved by the NERC Board of Directors, which outlines the following:

   1.1 requirements for administering the system operator examinations;

   1.2 requirements for exam eligibility;

   1.3 requirements for awarding the Certification Credential;

   1.4 requirements for Certification Credential maintenance;

   1.4.1 NERC requires a system operator to earn CE Hours in NERC-Approved Learning Activities within the three-year period preceding

the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual.

1.4.2 NERC requires a system operator to request a renewal and submit the appropriate fee for Certification renewal evaluation.

1.5 dispute resolution procedures; and

1.6 disciplinary action guidelines.

2. PCGC shall develop a Credential Maintenance Program and maintain an accompanying manual, which outlines the following:

2.1 requirements for approving contining education Providers and Learning Activities;

2.2 requirements for auditing continuing education Providers and Learning Activities;

2.3 multi-layer review process for disputed application reviews, interpretations of guideline and standards, probation or suspension of NERC-approved Provider status, and credential maintenance disputes; and,

2.4 requirements on fees for continuing education Providers and Learning Activities.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the

required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC

chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

    5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

    1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

3.2. Probation: A letter will be sent from NERC to the offender specifying:

3.2.1. The length of time of the probationary period (to be determined by the PCGC).

3.2.2. Credential will remain valid during the probationary period.

3.2.3. The probationary period does not affect the expiration date of the current certificate.

3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

3.3.1. The length of time of the probationary period (to be determined by the PCGC).

3.3.2. Credential is no longer valid.

3.3.3. Successfully passing an exam will be required to become recertified.

3.3.4. An exam will not be authorized until the revocation period expires

3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing

1. The PCGC shall develop exams to evaluate individual competence in a manner that is objective, and fair to all candidates, and to determine essential knowledge relating to NERC Reliability Standards as well as principles of the Bulk Power System operations.

2. The PCGC shall oversee exam administration as follows:

1.1 Adopt and implement a formal policy of periodic review of exams to assess ongoing relevance to knowledge and skill needed in the discipline; and

1.2 Conduct ongoing studies to substantiate the reliability and validity of exams.

3. The PCGC shall develop and utilize policies and procedures to ensure the integrity and security of exams and the transparency of test administration consistent with the following:

    1.1 The PCGC shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted standards in the psychometric community as being fair and reasonable;

    1.2 The PCGC shall conduct ongoing studies to substantiate the reliability and validity of the exams;

    1.3 The PCGC shall dictate how long examination records are kept in their original format; and

    1.4 The PCGC shall demonstrate that different revisions of the exams assess equivalent content.

607. Public Information About the Personnel Certification Program

The PCGC shall maintain and publish the following:

1. a summary of the information, knowledge, or functions covered by each examination administered pursuant to the Personnel Certification Program; and

2. an annual summary of Certification activities for the Personnel Certification Program, including, the number of examinations delivered, the number of applicants who passed, the number of applicants who failed, and the number of applicants certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The PCGC shall adhere to the following with respect to personnel applicants:

1. comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services;

2. make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants;

3. implement a formal policy for the periodic review of eligibility criteria and application procedures for fairness;

4. provide competently proctored examination sites; and

5. uniformly provide applicants with examination results and give content summary after the examination.

609. Responsibilities to Employers of Certified Personnel

The PCGC shall adhere to the following with respect to certified personnel:

1. demonstrate that the exams adequately measure essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable;

3. maintain, in an electronic format, a current list of those personnel certified in the programs and have policies and procedures that delineate what information about a Certification Credential holder may be made public and under what circumstances; and

4. develop formal policies and procedures for discipline of a Certification Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

610. [PLACEHOLDER]

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

    1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

    1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

    1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

    1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

    1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems,

operational readiness of the affected Regional Entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

   3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

   3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Assuring the Reliable Operation of the North American Bulk Power System requires informed knowledgeable and skilled personnel. NERC shall oversee the coordination and delivery of learning materials, resources, and activities to allow for training and education of:

1. ERO Enterprise staff supporting statutory and delegation-related activities; and

2. Bulk Power System industry participants consistent with ERO functional program requirements.

902. [PLACEHOLDER]

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall participate in and, where appropriate, coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America. NERC shall, where appropriate, take a leadership role in Critical Infrastructure protection of the electricity sector to help reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electricity Information Sharing and Analysis Center (E-ISAC)

    1.1 NERC shall operate the E-ISAC on behalf of the electricity sector. In 1998, the U.S. Secretary of Energy asked NERC to serve as the information sharing and analysis center for the electricity sector, in implementation of Presidential Decision Directive 63, as part of a public/private partnership to deal with matters related to infrastructure security.

    1.2 The E-ISAC gathers and analyzes security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity sector, across interdependent sectors, and with government partners. The E-ISAC, in collaboration with the United States Department of Energy (DOE) and the Electricity Subsector Coordinating Council (ESCC), serves as the primary security communications channel for the electricity sector and enhances the sector's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents.

    1.3 NERC shall improve the capability of the E-ISAC to fulfill its mission.

    1.4 NERC shall work closely with governmental agencies, including, among others, DOE, the United States Department of Homeland Security, Natural Resources Canada, and Public Safety Canada.

    1.5 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.6 NERC shall coordinate with the ESCC and the Government Coordinating Council.

1.7 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, other ISACs, and the National Infrastructure Advisory Council.

1.8 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

1.9 As part of the E-ISAC's efforts to fulfill its mission, it may issue, as circumstances warrant, written communications, referred to as All Points Bulletins (APBs), to disseminate critical security information rapidly to electricity sector asset owners and operators as security threats and attacks develop, and critical, time-sensitive security information becomes available. The E-ISAC shall share all APBs with Federal Energy Regulatory Commission staff no later than at the time of issuance.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, through identification, protection, detection, response, and recovery functions.

2.2 NERC shall consider security along-side considerations of reliability and resiliency of the Bulk Power System.

2.3 NERC shall keep abreast of the changing threat environment through collaboration with appropriate government agencies.

2.4 NERC shall develop criteria to identify critical physical and cyber assets, assess security threats, identify risk assessment methods, and assess effectiveness of physical and cyber protection measures.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness of security matters and respond to the security needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and endeavor to improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.10 NERC shall improve methods to assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources provided for in the budget to carry out the ERO program responsibilities;

explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding

requirement (including Regional Entity costs for delegated functions), and (3) the mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[5] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional

[5] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

Entity will collect directly from the Load-Serving Entities or as otherwise provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity

in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted on NERC's website at approximately the same time that notice is given to

committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Electric Infrastructure Information; (iii) Critical Energy Infrastructure Information; (iv) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (v) work papers, including any records produced for or created in the course of an evaluation or audit; (vi) investigative files, including any records produced for or created in the course of an investigation; or (vii) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Electric Infrastructure** means a system or asset of the bulk power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

4. **Critical Electric Infrastructure Information** means information related to proposed or existing Critical Electric Infrastructure. Such term includes information that qualifies as Critical Energy Infrastructure Information as defined herein.

5. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

6. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

7. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the

"Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls, and by adding any labels required by rules or regulations of an Applicable Governmental Authority. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity. Commission regulations regarding access to Critical Electric Infrastructure Information or Critical Energy Infrastructure Information will also apply as appropriate when the Commission is the Submitting Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality

in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement provided by NERC.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion

of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Resolved Noncompliance** — Nothing in this Section 1500 shall prohibit the disclosure of a noncompliance at the point when the matter is filed with an Applicable Governmental Authority, a Registered Entity admits to the violation, or the Registered Entity and the CEA resolve the noncompliance in accordance with Appendix 4C.

2. **Information Exchange** — NERC and the Regional Entities are authorized to exchange Confidential Information to perform their respective statutory and delegated functions, including, but not limited to, evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information consistent with the delegation agreement.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses Confidential Information may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500 precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating"

or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

    2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

    2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

    2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

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	)

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

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 **5**

Standard of Review **6**

Procedural History **7**

Development History (Pre-1996 to 2024) **8**

Structural Overview of BAL-002-WECC-3 ..... **11**

Purpose 11

Applicability 11

Requirements 11

Requirement R1 11

Requirement R2 11

Requirement R3 12

Requirement R4 12

Reliability will be Maintained **13**

Vital Public Interests will be Enhanced **18**

Market Timing Issues 18

Capacity Could be Better Utilized than Simply Holding Reserve 20

Conclusion **22**

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

[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]

[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.

---

[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.*

---

[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.

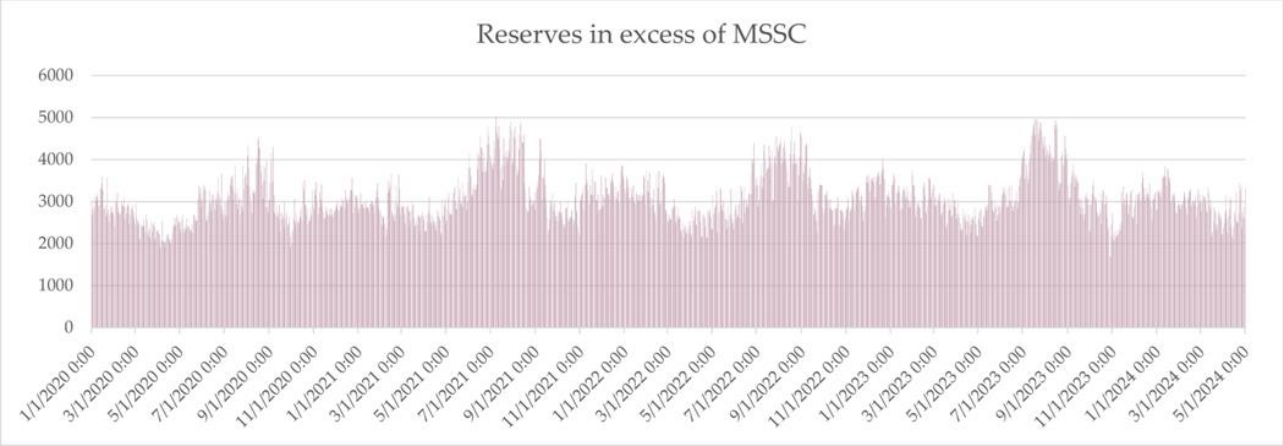


Figure 1: Reserves in excess of MSSC

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)

[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.

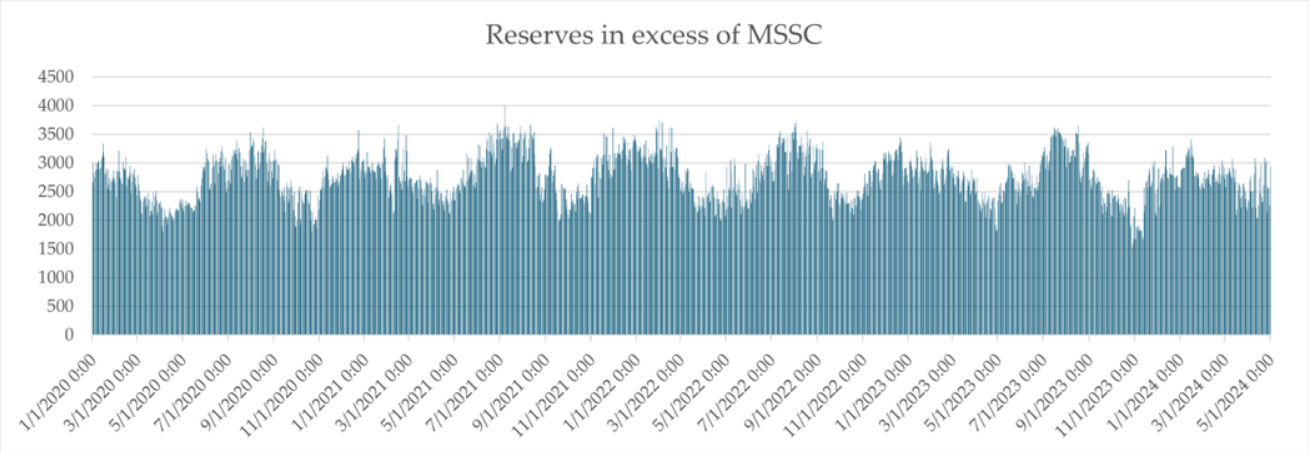


Figure 2: Reserves in excess of MSSC; January 1, 2020, through May 1, 2024

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	)
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

Exhibit 2-152:
WECC Risk Factor Criteria

WECC Risk Factor Criteria for Inherent Risk Assessment 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 - or - Entity has low impact BCS(s) with external routable connectivity (LERC) - or - Entity has medium impact BCSs	Entity has medium impact BCS(s) with at least one ICCP connection - or - 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 - or - Entity has over 1,000 miles of transmission lines 100 kV or greater	Entity has transmission facilities greater than 300 kV - or - 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 - or - 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 - or - 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 - or - 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 - or - 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 - or - 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 - or - 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) - or - Entity provides switching or other logistics based on the direction from a different entity responsible for the restoration plan	Entity is an RC - or - 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	)

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

Exhibit 2-153:
WECC Reliability Assessment Webpage

LOGIN

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

@ 2026 WECC

LEGAL

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	)

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

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

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

Microsoft Teams Need help?

Join the meeting now

Meeting ID: 256 665 160 678 92
Passcode: Ei7NT9X3

For organizers: Meeting options

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	)

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

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-	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 firm

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.

Columbia River Treaty Regime

Sources

https://www.state.gov/bureau-of-western-hemisphere-affairs/details-about-the-key-elements-agreed-between-th

(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 a time. After consulting with BPA, we also interpret that BC could demand this amount for a sustained long perio such as for two weeks or more, without violating the generation amounts of the treaty (2) which is itself interpre annual average energy for the treaty. This means the treaty's capacity could be requested for longer than the r periods and present a firm requirement. **Therefore, the capacity component of the treaty was modeled as a 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

ne-united-states-and-canada-regarding-modernization-of-the-columbia-river-treaty-regime

any point in
d of time,
ted as the
eliability risk
a firm

In-Development Resources

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

Plant-level list in-development resources within the Greater Northwest Study Region with commissi
between 2025-2030. In-development resources are WECC ADS 2034 facilities with confirmed proje
project name, and can be verified online. In-development resources include coal-to-gas plant conve
Pacificorp's 2025 IRP. Plants with commission dates before January 1 are considered available in t
Each resource is assgined to a Transmission Zone based on physical location within the Greater N
zonal modeling.

Annual Capacity Additions (Nameplate MW)			
	2025	2026	2027
Hydro	99	251	78
Nuclear	-	-	-
Coal	-	-	-
Gas	1,339	357	-
Other	-	-	-
Wind	1,026	1,126	460
Solar	344	1,396	125
BTM Solar	-	-	-
Battery Storage	460	545	-
Demand Response	-	-	-

Total	3,267	3,676	663

Source	GeneratorKey	Name	State
ADS 2034	2177	Meyers Falls 1 HY	WA
ADS 2034	2197	Upper Falls Post St 1 HY	WA
ADS 2034	2393	Cedar Falls 2 HY	WA
ADS 2034	2394	Cedar Falls 1 HY	WA
ADS 2034	3472	Thompson Falls 2 HY	MT
ADS 2034	3479	Thompson Falls 6 HY	MT
ADS 2034	3480	Thompson Falls 5 HY	MT
ADS 2034	3481	Thompson Falls 4 HY	MT
ADS 2034	3486	Holter 4 HY	MT
ADS 2034	3487	Holter 3 HY	MT
ADS 2034	3488	Holter 2 HY	MT
ADS 2034	3489	Ryan 6 HY	MT
ADS 2034	3490	Ryan 5 HY	MT
ADS 2034	3515	Ryan 3 HY	MT
ADS 2034	3517	Ryan 1 HY	MT
ADS 2034	3531	Holter 1 HY	MT
ADS 2034	3537	Thompson Falls 3 HY	MT
ADS 2034	3539	Thompson Falls 1 HY	MT
ADS 2034	4925	Boundary 1 HY	WA
ADS 2034	4966	Long_Lake_1	WA
ADS 2034	7473	Lagrande 2 HY	WA
ADS 2034	7474	Lagrande 3 HY	WA
ADS 2034	7475	Lagrande 4 HY	WA
ADS 2034	7606	Long_Lake_2	WA
ADS 2034	7607	Long Lake 3 HY	WA
ADS 2034	7608	Long Lake 4 HY	WA
ADS 2034	8613	Ryan 2 HY	MT
ADS 2034	8614	Ryan 4 HY	MT
ADS 2034	9698	Gorge 1 HY	WA

ADS 2034	9699	Gorge 2 HY	WA
ADS 2034	18045	Boswell Springs Wind WT	WY
ADS 2034	18048	Cedar Creek Wind WT	ID
ADS 2034	18179	Hauser Agg HY	MT
ADS 2034	18210	Uinta Agg HY	UT
ADS 2034	18218	Utility Solar+Storage - PV - S-Or	OR
ADS 2034	18224	Big Fork 1 HY	MT
ADS 2034	18345	Glen Canyon Solar A PV-T	UT
ADS 2034	19147	Tower Rd Solar PV-T	OR
ADS 2034	19260	Farmers Irrigation District Coppe	OR
ADS 2034	20916	Oregon Trail Solar PV-T	OR
ADS 2034	20917	Green River Energy Center PV-T	UT
ADS 2034	20962	Cedar Springs Wind IV WT	WY
ADS 2034	20963	Anticline Wind WT	WY
ADS 2034	20964	Two Rivers Wind LLCWT	WY
ADS 2034	21121	Franklin BESS paired with Solar	ID
ADS 2034	21163	Oregon Trail BESS BA	OR
ADS 2034	21164	Tower Rd BESS BA	OR
ADS 2034	21215	Jim Bridger 1 ST	WY
ADS 2034	21216	Jim Bridger 2 ST	WY
ADS 2034	21401	Yellowstone County Generating	MT
ADS 2034	21402	Yellowstone County Generating	MT
ADS 2034	21403	Yellowstone County Generating	MT
ADS 2034	21404	Yellowstone County Generating	MT
ADS 2034	21405	Yellowstone County Generating	MT
ADS 2034	21406	Yellowstone County Generating	MT
ADS 2034	21407	Yellowstone County Generating	MT
ADS 2034	21408	Yellowstone County Generating	MT
ADS 2034	21409	Yellowstone County Generating	MT
ADS 2034	21410	Yellowstone County Generating	MT
ADS 2034	21411	Yellowstone County Generating	MT
ADS 2034	21412	Yellowstone County Generating	MT
ADS 2034	21413	Yellowstone County Generating	MT
ADS 2034	21414	Yellowstone County Generating	MT
ADS 2034	21415	Yellowstone County Generating	MT
ADS 2034	21416	Yellowstone County Generating	MT
ADS 2034	21417	Yellowstone County Generating	MT
ADS 2034	21418	Yellowstone County Generating	MT
ADS 2034	21423	DaveJohnston 1 1 ST	WY
ADS 2034	21432	Naughton 1 (natural gas convers	WY
ADS 2034	21433	Naughton 2 (natural gas convers	WY
ADS 2034	21678	Additional Hemingway Standalo	ID
ADS 2034	21679	Elmore Distributed BESS BA	ID
ADS 2034	21680	Happy Valley BESS I 1 BA	ID
ADS 2034	21681	Happy Valley BESS II 1 BA	ID
ADS 2034	21682	Kuna BESS 1 BA	ID
ADS 2034	21683	Melba Distributed BESS BA	ID
ADS 2034	21735	Parowan Solar BA	UT
ADS 2034	21749	Pump Storage - West 1 PS	OR
ADS 2034	21752	Coffee Creek 1 BA	OR
ADS 2034	21753	Constable BESS 1 BA	OR
ADS 2034	21754	Seaside BESS 1 BA	OR
ADS 2034	21755	Troutdale BESS 1 BA	OR
ADS 2034	22116	Pleasant Valley Solar II 1 PV-T	ID
ADS 2034	22212	Arco Wind WT	ID
ADS 2034	22215	Faraday Solar B LLC PV-T	UT
ADS 2034	22217	Hornshadow Solar II LLC PV-T	UT
ADS 2034	22218	Hornshadow Solar LLC PV-T	UT
ADS 2034	22220	Parowan Solar PV-T	UT
ADS 2034	22231	Rock Creek I Wind 32 WT	WY

ADS 2034	22232	Rock Creek II Wind 66 WT	WY
ADS 2034	22256	Buckaroo Solar 1 PV-T	OR
ADS 2034	22257	Buckaroo Solar 2 PV-T	OR
ADS 2034	22262	Antelope Creek Solar LLC PV-T	OR
ADS 2034	22264	Black Rock Solar PV-T	WA
ADS 2034	22267	Green Solar LLC PV-T	OR
ADS 2034	22268	High Top Solar PV-T	WA
ADS 2034	22270	Orchard Knob Solar PV-T	OR
ADS 2034	22274	Pilot Rock Solar I PV-T	OR
ADS 2034	22275	Pilot Rock Solar II PV-T	OR
ADS 2034	22276	Pine Grove Solar LLC PV-T	OR
ADS 2034	22281	Sunset Ridge Solar LLC PV	OR
ADS 2034	22292	Clearwater II 37 WT	MT
ADS 2034	22323	BHCE 100 MW Wind WT	CO
ADS 2034	22340	Beaver Creek 1 WT	MT
ADS 2034	22487	Sprague Hydro (North Fork) 1 H	OR
ADS 2034	22546	Wallowa Falls 1 HY	OR
ADS 2034	22567	DaveJohnston 2 2 ST	WY
Pacificorp 2025 IRP	Pacificorp 2025 IRP	E3 Dave Johnston 4 Coal-to-Ga	WY

ıanchor-data-set-ads

on dates
ect location,
ersions in
the study year.
orthwest for

2028	2029	2030		Total
2	91	-		522
-	-	-		-
-	-	-		-
-	205	360		2,261
-	-	-		-
-	-	-		2,611
-	-	-		1,866
-	-	-		-
-	-	-		1,005
-	-	-		-
2	296	360		8,264

County	Tranmission Zone	Rated Capacity (Nameplate MW)	Resource Type	Balancing Authority
NA	PNW_NE	1	Hydro	AVA
NA	PNW_NE	10	Hydro	AVA
NA	PNW_NW	15	Hydro	PSEI
NA	PNW_NW	15	Hydro	PSEI
NA	Inland_NW	5	Hydro	NWMT
NA	Inland_NW	5	Hydro	NWMT
NA	Inland_NW	5	Hydro	NWMT
NA	Inland_NW	5	Hydro	NWMT
Lewis&Clark	Inland_NW	10	Hydro	NWMT
Lewis&Clark	Inland_NW	10	Hydro	NWMT
Lewis&Clark	Inland_NW	10	Hydro	NWMT
NA	Inland_NW	8	Hydro	NWMT
NA	Inland_NW	8	Hydro	NWMT
NA	Inland_NW	8	Hydro	NWMT
NA	Inland_NW	8	Hydro	NWMT
Lewis&Clark	Inland_NW	10	Hydro	NWMT
NA	Inland_NW	5	Hydro	NWMT
NA	Inland_NW	5	Hydro	NWMT
NA	PNW_NW	158	Hydro	SCL
Lincoln	PNW_NE	9	Hydro	AVA
NA	PNW_NW	6	Hydro	TPWR
NA	PNW_NW	6	Hydro	TPWR
NA	PNW_NW	6	Hydro	TPWR
Lincoln	PNW_NE	9	Hydro	AVA
NA	PNW_NE	18	Hydro	AVA
NA	PNW_NE	18	Hydro	AVA
Cascade	Inland_NW	9	Hydro	NWMT
Cascade	Inland_NW	9	Hydro	NWMT
NA	PNW_NW	37	Hydro	SCL

NA	PNW_NW	37	Hydro	SCL
Sweetwater	Central_West	320	Wind	PACE
Power	Central_West	152	Wind	PACE
Lewis&Clark	Inland_NW	17	Hydro	NWMT
Uintah	Central_West	1	Hydro	PACE
NA	PNW_SW	1	Battery Storage	PACW
Flathead	PNW_NE	2	Hydro	BPAT
Kane	Central_West	95	Solar	PACE
Morrow	PNW_NE	120	Solar	BPAT
Hood River	PNW_SW	2	Hydro	PACW
Gilliam	PNW_NE	41	Solar	BPAT
Emery	Central_West	400	Solar	PACE
NA	Central_West	350	Wind	PACE
NA	Central_West	101	Wind	PACE
Carbon	Central_West	280	Wind	PACE
Twin Falls	Central_West	60	Battery Storage	IPCO
Gilliam	PNW_NE	41	Battery Storage	BPAT
Morrow	PNW_NE	60	Battery Storage	BPAT
Sweetwater	Central_West	578	Gas	PACE
Sweetwater	Central_West	586	Gas	PACE
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Yellowstone	Inland_NW	10	Gas	NWMT
Converse	Central_West	99	Gas	PACE
Lincoln	Central_West	156	Gas	PACE
Lincoln	Central_West	201	Gas	PACE
Owyhee	Central_West	36	Battery Storage	IPCO
Elmore	Central_West	3	Battery Storage	IPCO
Canyon	Central_West	39	Battery Storage	IPCO
Canyon	Central_West	39	Battery Storage	IPCO
Ada	Central_West	150	Battery Storage	IPCO
Canyon	Central_West	2	Battery Storage	IPCO
Iron	Central_West	58	Battery Storage	PACE
Douglas	PNW_SW	35	Hydro	PACW
Washington	PNW_NE	17	Battery Storage	BPAT
Washington	PNW_SW	100	Battery Storage	BPAT
Multnomah	PNW_SW	200	Battery Storage	BPAT
Multnomah	PNW_NE	200	Battery Storage	BPAT
Ada	Central_West	125	Solar	IPCO
Bonneville	Central_West	360	Wind	PACE
Utah	Central_West	525	Solar	PACE
Emery	Central_West	200	Solar	PACE
Emery	Central_West	100	Solar	PACE
Iron	Central_West	58	Solar	PACE
Carbon	Central_West	195	Wind	PACE

Albany	Central_West	403	Wind	PACE
Pendleton	PNW_SW	2	Solar	PACW
Pendleton	PNW_SW	3	Solar	PACW
Jackson	PNW_SW	2	Solar	PACW
Yakima	PNW_NE	100	Solar	BPAT
Culver	PNW_SW	3	Solar	TH_Malin
Yakima	PNW_NE	80	Solar	BPAT
Polk	PNW_NE	2	Solar	BPAT
Umatilla	PNW_SW	2	Solar	PACW
Umatilla	PNW_SW	3	Solar	PACW
Klamath	PNW_SW	1	Solar	TH_Malin
Klamath	PNW_SW	2	Solar	TH_Malin
Custer	Central_West	103	Wind	PACE
TBD	PNW_NE	100	Wind	BPAT
Gallatin	Inland_NW	248	Wind	NWMT
Klamath	PNW_SW	1	Hydro	PACW
NA	PNW_SW	1	Hydro	PACW
Converse	Central_West	106	Gas	PACE
Converse	Central_West	360	Gas	PACE

Commission Date	First Available Year
12/31/2024	2025
1/4/2026	2027
1/1/2026	2027
1/1/2026	2027
6/1/2025	2026
12/1/2024	2025
12/1/2024	2025
3/31/2025	2026
6/15/2025	2026
7/1/2025	2026
8/25/2025	2026
1/1/2025	2026
3/9/2025	2026
12/1/2024	2025
12/1/2024	2025
12/1/2025	2026
4/1/2025	2026
6/1/2025	2026
8/1/2025	2026
12/31/2024	2025
1/1/2024	2025
1/1/2024	2025
1/1/2024	2025
12/31/2024	2025
12/1/2025	2026
1/1/2028	2029
12/13/2024	2025
12/31/2024	2025
1/1/2028	2029

1/1/2028	2029
4/1/2024	2025
4/1/2024	2025
12/31/2024	2025
12/1/2025	2026
1/1/2024	2025
1/1/2027	2028
1/1/2024	2025
12/1/2024	2026
1/1/2026	2027
12/31/2025	2026
6/15/2025	2026
12/31/2024	2025
12/31/2024	2025
3/31/2025	2026
6/1/2024	2025
12/31/2025	2026
12/31/2025	2026
4/1/2024	2025
4/1/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
5/15/2024	2025
1/1/2029	2029
1/1/2026	2026
1/1/2026	2026
6/1/2024	2025
6/1/2024	2025
6/1/2025	2026
6/1/2025	2026
6/1/2025	2026
6/1/2024	2025
12/1/2024	2025
1/1/2026	2027
6/1/2025	2026
12/31/2024	2025
6/1/2025	2026
12/31/2024	2025
12/1/2026	2027
12/1/2026	2027
9/30/2025	2026
6/30/2025	2026
6/30/2025	2026
12/1/2024	2025
6/1/2025	2026

9/1/2025	2026
9/30/2025	2026
9/30/2025	2026
4/19/2024	2025
1/1/2024	2025
3/15/2024	2025
4/1/2024	2025
2/23/2024	2025
9/30/2025	2026
9/30/2025	2026
2/16/2024	2025
7/25/2024	2025
1/2/2024	2025
1/1/2026	2027
3/1/2025	2026
1/1/2024	2025
1/1/2026	2027
1/1/2029	2029
12/31/2029	2030

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 firm

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	)
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

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%

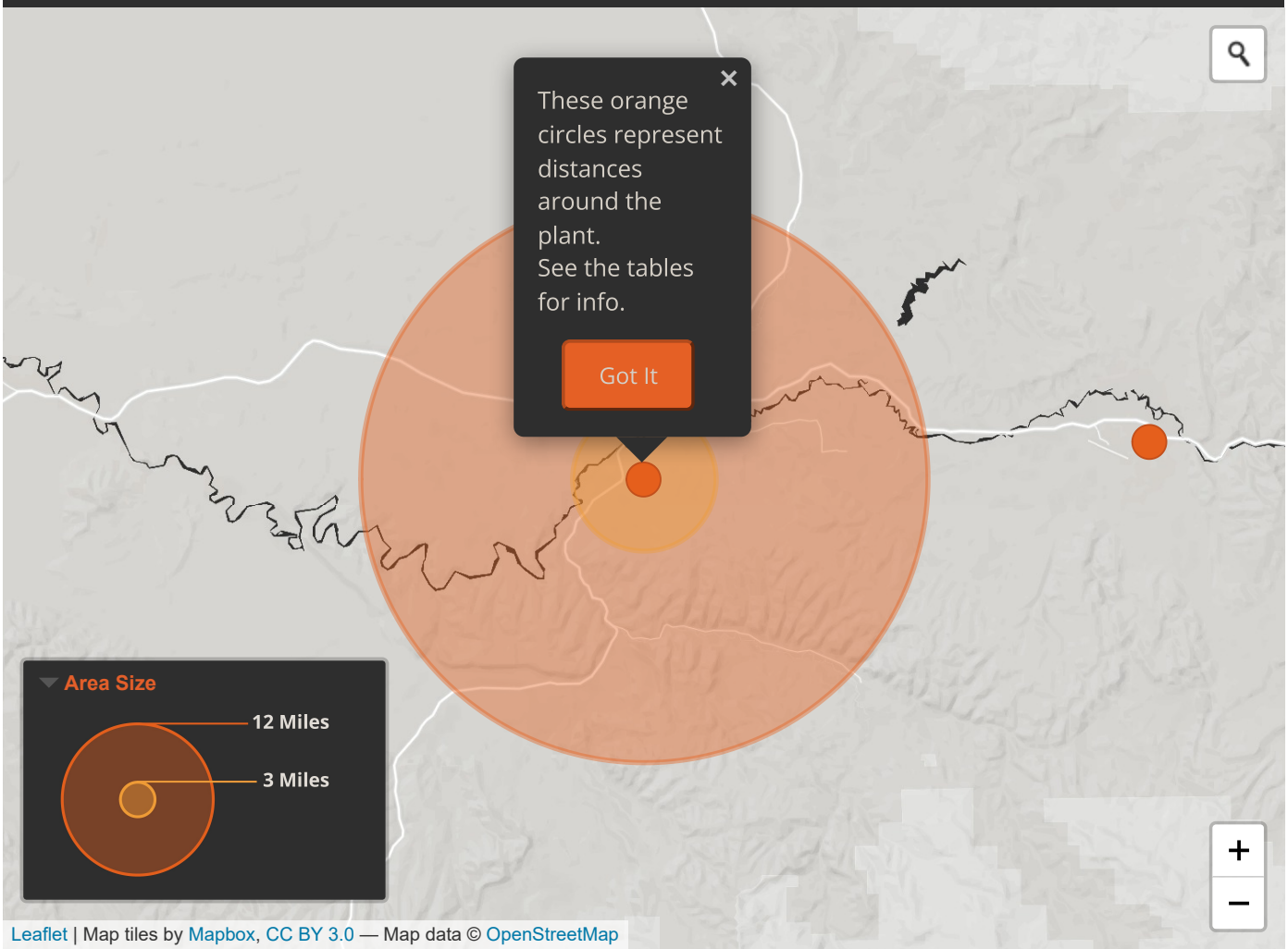
Size of Plant 1,304 MW

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



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	)
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

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	)

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

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

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

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

LEGAL NOTICE

This report ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("Sargent & Lundy"), expressly for the sole use of U.S. Energy Information Administration ("Client") in accordance with the agreement between Sargent & Lundy and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) Sargent & Lundy prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by Sargent & Lundy; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

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.

55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000

CONTENTS

Section Page

EXECUTIVE SUMMARY 1

Identifying Impacts of Aging on Generation Cost and Operation 1

Modeling Impacts of Aging in EIA Projections 3

Existing Treatment of Aging in EIA's Electricity Market Module 3

Need for Update to EIA's Treatment of Aging 3

Analysis of Aging Impacts in Publicly-Reported Cost Information 4

Cost Breakdowns in Reported Data 4

Data Compilation 5

Identifying Changes in Spending Patterns over Plant Life 6

Differences in Spending Approach by Plant Type 6

Potential Benefits of CAPEX and O&M Spending on Future Spending 6

Potential Impacts of Plant Age on Future Spending 7

Effect of Plant Capacity (MW) 7

Effect of Plant Capacity Factor 8

Effect of External Market Conditions 9

Effect of Regulatory Environment 10

Effect of Fuel Characteristics 10

Effect of Flue Gas Desulfurization 10

Proposed Updates to EMM Methodology 11

Coal Steam 11

Gas/Oil Steam 13

Gas/Oil Combined Cycle and Gas/Oil Combustion Turbine 15

Conventional Hydroelectric 16

Pumped Storage 17

Solar Photovoltaic 17

Solar Thermal 18

Geothermal 18

Wind 19

Recommended Areas for Further Study 20

CONTENTS

Section Page

1. INTRODUCTION 1-1

2. ASSESSMENT METHODOLOGY 2-1

2.1 Background 2-1

2.2 Sources of Cost Information 2-2

2.2.1 FERC Form 1 Data 2-2

2.2.2 Sargent & Lundy Internal Data 2-5

2.2.3 Other Data Sources 2-6

2.3 Data Validation 2-6

2.4 Data Normalization 2-9

2.5 Statistical Tests 2-11

2.5.1 Consistency of FERC Form 1 and Sargent & Lundy Internal Data 2-11

2.5.2 Significance of Plant Age on Annual Capital and O&M Expenditures 2-13

2.5.3 Autocorrelation of Time Series Data 2-14

3. COAL STEAM 3-1

3.1 Data Description 3-1

3.2 Summary of Results 3-2

3.2.1 Recommended CAPEX Values 3-2

3.2.2 Recommended O&M Values 3-4

3.2.3 Effect of Plant Capacity Factor 3-5

3.2.4 Effect of External Market Conditions 3-6

3.2.5 Effect of Regulatory Environment 3-7

3.2.6 Effect of Fuel Characteristics 3-8

4. GAS/OIL STEAM 4-1

4.1 Data Description 4-1

4.2 Summary of Results 4-1

4.2.1 Recommended CAPEX Values 4-1

CONTENTS

Section Page

4.2.2 Recommended O&M Values 4-3
4.2.3 Effect of Plant Capacity Factor 4-4
4.2.4 Effect of External Market Conditions 4-4

5. GAS/OIL COMBINED CYCLE 5-1

5.1 Data Description 5-1

5.2 Summary of Results 5-2

6. GAS/OIL COMBUSTION TURBINE 6-1

6.1 Data Description 6-1

6.2 Summary of Results 6-2

7. CONVENTIONAL HYDROELECTRIC 7-1

7.1 Data Description 7-1

7.2 Summary of Results 7-2

8. PUMPED HYDROELECTRIC STORAGE 8-1

8.1 Data Description 8-1

8.2 Summary of Results 8-1

9. SOLAR PHOTOVOLTAIC 9-1

9.1 Data Description 9-1

9.2 Summary of Results 9-1

10. SOLAR THERMAL 10-1

10.1 Data Description 10-1

10.2 Summary of Results 10-1

CONTENTS

Section Page

11. GEOTHERMAL 11-1

11.1 Data Description 11-1

11.2 Summary of Results 11-1

12. WIND 12-1

12.1 Data Description 12-1

12.2 Summary of Results 12-2

APPENDIX A. REGRESSION ANALYSIS – COAL STEAM A-1

Capital Expenditures – All Plant Sizes A-2

Operations & Maintenance Expenditures – All Plant Sizes A-3

Capital Expenditures – Less than 500 MW A-4

Operations & Maintenance Expenditures – Less than 500 MW A-5

Capital Expenditures – Between 500 MW and 1,000 MW A-7

Operations & Maintenance Expenditures – Between 500 MW and 1,000 MW A-8

Capital Expenditures – Between 1,000 MW and 2,000 MW A-9

Operations & Maintenance Expenditures – Between 1,000 MW and 2,000 MW A-10

Capital Expenditures – Greater than 2,000 MW A-12

Operations & Maintenance Expenditures – Greater than 2,000 MW A-13

Capital Expenditures – Capacity Factor Less than 50% A-14

Operations & Maintenance Expenditures – Capacity Factor less than 50% A-15

Capital Expenditures – Capacity Factor Greater than 50% A-17

Operations & Maintenance Expenditures – Capacity Factor Greater than 50% A-18

Capital Expenditures – Regulated vs. Deregulated A-19

Operations & Maintenance Expenditures – Regulated vs. Deregulated A-20

CONTENTS

Section Page

Capital Expenditures – FGD vs. No FGD A-20

Operations & Maintenance Expenditures – FGD vs. No FGD A-21

Capital Expenditures – Bituminous vs. Subbituminous A-22

Operations & Maintenance Expenditures – Bituminous vs. Subbituminous A-23

Effect of Plant Capacity Factor A-24

APPENDIX B. REGRESSION ANALYSIS – GAS/OIL STEAM B-1

Capital Expenditures – All Plant Sizes B-2

Operations & Maintenance Expenditures – All Plant Sizes B-2

Capital Expenditures – Less than 500 MW B-4

Operations & Maintenance Expenditures – Less than 500 MW B-4

Capital Expenditures – Between 500 MW and 1,000 MW B-6

Operations & Maintenance Expenditures – Between 500 MW and 1,000 MW B-7

Capital Expenditures – Greater than 1,000 MW B-8

Operations & Maintenance Expenditures – Greater than 1,000 MW B-9

APPENDIX C. REGRESSION ANALYSIS – GAS/OIL COMBINED CYCLE C-1

Capital Expenditures – All Plant Sizes C-2

Operations & Maintenance Expenditures – All Plant Sizes C-2

Capital Expenditures – Less than 500 MW C-4

Operations & Maintenance Expenditures – Less than 500 MW C-5

Capital Expenditures – Between 500 MW and 1,000 MW C-6

Operations & Maintenance Expenditures – Between 500 MW and 1,000 MW C-7

Capital Expenditures – Greater than 1,000 MW C-9

Operations & Maintenance Expenditures – Greater than 1,000 MW C-9

CONTENTS

Section Page

Capital Expenditures – Capacity Factor Less than 50% C-11

Operations & Maintenance Expenditures – Capacity Factor Less than 50% C-12

Capital Expenditures – Capacity Factor Greater than 50% C-13

Operations & Maintenance Expenditures – Capacity Factor Greater than 50% C-14

APPENDIX D. REGRESSION ANALYSIS – GAS/OIL COMBUSTION TURBINE D-1

Capital Expenditures – All Plant Sizes D-2

Operations & Maintenance Expenditures – All Plant Sizes D-2

Capital Expenditures – Less than 100 MW D-4

Operations & Maintenance Expenditures – Less than 100 MW D-5

Capital Expenditures – Between 100 MW and 300 MW D-6

Operations & Maintenance Expenditures – Between 100 MW and 300 MW D-7

Capital Expenditures – Greater than 300 MW D-9

Operations & Maintenance Expenditures – Greater than 300 MW D-10

APPENDIX E. REGRESSION ANALYSIS – CONVENTIONAL HYDROELECTRIC E-1

Capital Expenditures – All Plant Sizes E-2

Operations & Maintenance Expenditures – All Plant Sizes E-3

APPENDIX F. REGRESSION ANALYSIS – PUMPED HYDROELECTRIC STORAGE F-1

Capital Expenditures – All Plant Sizes F-2

Operations & Maintenance Expenditures – All Plant Sizes F-3

APPENDIX G. REGRESSION ANALYSIS – SOLAR PHOTOVOLTAIC G-1

Capital Expenditures G-2

Operations & Maintenance Expenditures G-4

CONTENTS

Section Page

APPENDIX H. REGRESSION ANALYSIS – SOLAR THERMAL H-1

APPENDIX I. REGRESSION ANALYSIS – GEOTHERMAL I-1

Capital Expenditures I-2

Operations & Maintenance Expenditures I-3

APPENDIX J. REGRESSION ANALYSIS – WIND J-1

Capital Expenditures J-2

Operations & Maintenance Expenditures J-8

TABLES AND FIGURES

Table or Figure — Page

Table ES-1 — Variables Affecting Annual Changes in Real Spending per kW 2
Table ES-2 — High Capacity Factor Coal Plants – Spending Comparison 10
Table ES-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors 11
Table ES-4 — Coal Steam O&M Comparison with Existing EMM 12
Table ES-5 — Gas/Oil Steam CAPEX Results 13
Table ES-6 — Gas/Oil Steam O&M Comparison with Existing EMM 14
Table ES-7 — Gas/Oil CC and CT CAPEX and O&M Comparison with Existing EMM 16
Table ES-8 — Hydroelectric CAPEX and O&M Comparison with Existing EMM 17
Table ES-9 — Pumped Storage CAPEX and O&M Comparison with Existing EMM 17
Table ES-10 — Geothermal CAPEX and O&M Comparison with Existing EMM 19
Table ES-11 — Wind CAPEX and O&M Comparison with Existing EMM 19
Table 2-1 — Summary of Valid Data Points 2-8
Table 3-1 — Coal Steam Cost Data Distribution 3-1
Table 3-2 — Effect of Data Validation Filters on Coal Data Points 3-2
Table 3-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors 3-3
Table 3-4 — Coal Plant Indicative Typical CAPEX Projects and Intervals 3-4
Table 3-5 — Coal Steam O&M Comparison with Existing EMM 3-5
Table 3-6 — High Capacity Factor Coal Plants – Spending Comparison 3-7
Table 4-1 — Gas/Oil Steam Cost Data Distribution 4-1
Table 4-2 — Gas/Oil Steam CAPEX Results 4-2
Table 4-3 — Gas/Oil Steam O&M Comparison with Existing EMM 4-3
Table 5-1 — Gas/Oil CC Cost Data Distribution 5-1
Table 5-2 — Gas/Oil CC CAPEX and O&M Comparison with Existing EMM 5-3
Table 6-1 — Gas/Oil Combustion Turbine Cost Data Distribution 6-1
Table 6-2 — Gas/Oil Combustion Turbine CAPEX and O&M Comparison with Existing EMM 6-3
Table 7-1 — Conventional Hydroelectric Cost Data Distribution 7-1
Table 7-2 — Hydroelectric CAPEX and O&M Comparison with Existing EMM 7-2
Table 8-1 — Pumped Storage Cost Data Distribution 8-1
Table 8-2 — Pumped Storage CAPEX and O&M Comparison with Existing EMM 8-2
Table 9-1 — Solar Photovoltaic Cost Data Distribution 9-1
Table 11-1 — Geothermal Cost Data Distribution 11-1
Table 11-2 — Geothermal CAPEX and O&M Comparison with Existing EMM 11-1

TABLES AND FIGURES

Table or Figure — Page

Table 12-1 — Wind Cost Data Distribution 12-1
Table 12-2 — Wind CAPEX and O&M Comparison with Existing EMM 12-2
Table A-1 — Regression Statistics – Coal CAPEX for All MW A-2
Table A-2 — Regression Statistics – Coal O&M for All MW A-3
Table A-3 — Regression Statistics – Coal CAPEX < 500 MW A-4
Table A-4 — Regression Statistics – Coal O&M < 500 MW A-5
Table A-5 — Regression Statistics – Coal CAPEX 500 MW to 1,000 MW A-7
Table A-6 — Regression Statistics – Coal O&M 500 MW to 1,000 MW A-8
Table A-7 — Regression Statistics – Coal CAPEX 1,000 MW to 2,000 MW A-9
Table A-8 — Regression Statistics – Coal O&M 1,000 MW to 2,000 MW A-10
Table A-9 — Regression Statistics – Coal CAPEX > 2,000 MW A-12
Table A-10 — Regression Statistics – Coal O&M > 2,000 MW A-13
Table A-11 — Regression Statistics – Coal CAPEX for Capacity Factor < 50% A-14
Table A-12 — Regression Statistics – Coal O&M for Capacity Factor < 50% A-15
Table A-13 — Regression Statistics – Coal CAPEX for Capacity Factor > 50% A-17
Table A-14 — Regression Statistics – Coal O&M for Capacity Factor > 50% A-18
Table A-15 — Regression Statistics – Coal CAPEX for Regulated/Deregulated A-19
Table A-16 — Regression Statistics – Coal CAPEX for FGD/No FGD A-21
Table A-17 — Regression Statistics – Coal CAPEX for Bituminous/Subbituminous A-22
Table B-1 — Regression Statistics – Gas/Oil Steam CAPEX for All MW B-2
Table B-2 — Regression Statistics – Gas/Oil Steam O&M for All MW B-3
Table B-3 — Regression Statistics – Gas/Oil Steam CAPEX < 500 MW B-4
Table B-4 — Regression Statistics – Gas/Oil Steam O&M < 500 MW B-5
Table B-5 — Regression Statistics – Gas/Oil Steam CAPEX 500 MW to 1,000 MW B-6
Table B-6 — Regression Statistics – Gas/Oil Steam O&M 500 MW to 1,000 MW B-7
Table B-7 — Regression Statistics – Gas/Oil Steam CAPEX > 1,000 MW B-8
Table B-8 — Regression Statistics – Gas/Oil Steam O&M > 1,000 MW B-9
Table C-1 — Regression Statistics – CC CAPEX for All MW C-2
Table C-2 — Regression Statistics – CC O&M for All MW C-3
Table C-3 — Regression Statistics – CC CAPEX < 500 MW C-4
Table C-4 — Regression Statistics – CC O&M < 500 MW C-5
Table C-5 — Regression Statistics – CC CAPEX 500 MW to 1,000 MW C-6

TABLES AND FIGURES

Table or Figure — Page

Table C-6 — Regression Statistics – CC O&M 500 MW to 1,000 MW C-7
Table C-7 — Regression Statistics – CC CAPEX > 1,000 MW C-9
Table C-8 — Regression Statistics – CC O&M > 1,000 MW C-10
Table C-9 — Regression Statistics – CC CAPEX for Capacity Factor < 50% C-11
Table C-10 — Regression Statistics – CC O&M for Capacity Factor < 50% C-12
Table C-11 — Regression Statistics – CC CAPEX for Capacity Factor > 50% C-13
Table C-12 — Regression Statistics – CC O&M for Capacity Factor > 50% C-14
Table D-1 — Regression Statistics – CT CAPEX for All MW D-2
Table D-2 — Regression Statistics – CT O&M for All MW D-3
Table D-3 — Regression Statistics – CT CAPEX < 100 MW D-4
Table D-4 — Regression Statistics – CT O&M < 100 MW D-5
Table D-5 — Regression Statistics – CT CAPEX 100 MW to 300 MW D-6
Table D-6 — Regression Statistics – CT O&M 100 MW to 300 MW D-7
Table D-7 — Regression Statistics – CT CAPEX > 300 MW D-9
Table D-8 — Regression Statistics – CT O&M > 300 MW D-10
Table E-1 — Regression Statistics – Hydroelectric CAPEX for All MW E-2
Table E-2 — Regression Statistics – Hydroelectric O&M for All MW E-3
Table F-1 — Regression Statistics – Pumped Hydroelectric CAPEX for All MW F-2
Table F-2 — Regression Statistics – Pumped Hydroelectric O&M for All MW F-3
Table G-1 — Regression Statistics – Solar PV CAPEX for All MW G-3
Table G-2 — Example of Calculation Method Differences G-4
Table G-3 — Summary of Industry O&M Cost Data for Solar PV G-8
Table I-1 — Regression Statistics – Geothermal CAPEX for All MW I-2
Table I-2 — Regression Statistics – Geothermal O&M for All MW I-3
Table I-3 — Geothermal All MW Summary of Results I-4
Table J-1 — Regression Statistics – Wind CAPEX for All MW J-2
Table J-2 — Wind All MW Summary of Results J-3
Table J-3 — Regression Statistics – Wind CAPEX for 0-100 MW J-3
Table J-4 — Wind < 100-MW Summary of Results J-4
Table J-5 — Regression Statistics – Wind CAPEX for 100-200 MW J-5
Table J-6 — Wind 100-200-MW Summary of Results J-6
Table J-7 — Regression Statistics – Wind CAPEX for Greater than 200 MW J-6

TABLES AND FIGURES

Table or Figure — Page

Table J-8 — Wind Greater than 200-MW Summary of Results J-7
Table J-9 — Regression Statistics – Wind O&M for All MW J-8
Table J-10 — Regression Statistics – Wind O&M for 0-100 MW J-9
Table J-11 — Regression Statistics – Wind O&M for 100-200 MW J-10
Table J-12 — Regression Statistics – Wind O&M Greater than 200 MW J-11

Figure ES-1 — Capacity Factor vs. Age for All Coal Plants 8
Figure ES-2 — Capacity Factor vs. Age for All Gas/Oil Steam Plants 8
Figure 2-1 — CAPEX vs. Age for 500-MW Coal Plants – FERC and Sargent & Lundy Data 2-12
Figure 2-2 — U.S. Power Plant Fleet Capacity by Age and Fuel Type 2-13
Figure 3-1 — Capacity Factor vs. Age for All Coal Plants 3-6
Figure 4-1 — Capacity Factor vs. Age for All Gas/Oil Steam Plants 4-4
Figure A-1 — Coal Steam Dataset – CAPEX for All MW Plant Sizes A-2
Figure A-2 — Coal Steam Dataset – O&M for All MW Plant Sizes A-3
Figure A-3 — Coal Steam Dataset – CAPEX for Less than 500-MW Plant Size A-5
Figure A-4 — Coal Steam Dataset – O&M for Less than 500-MW Plant Size A-6
Figure A-5 — Coal Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size A-7
Figure A-6 — Coal Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size A-8
Figure A-7 — Coal Steam Dataset – CAPEX for 1,000-MW to 2,000-MW Plant Size A-10
Figure A-8 — Coal Steam Dataset – O&M for 1,000-MW to 2,000-MW Plant Size A-11
Figure A-9 — Coal Steam Dataset – CAPEX for Greater than 2,000-MW Plant Size A-12
Figure A-10 — Coal Steam Dataset – O&M for Greater than 2,000-MW Plant Size A-13
Figure A-11 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor < 50% A-15
Figure A-12 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor < 50% A-16
Figure A-13 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor > 50% A-17
Figure A-14 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor > 50% A-18
Figure A-15 — Coal Steam Dataset – CAPEX for Regulated/Deregulated A-19
Figure A-16 — Coal Steam Dataset – O&M for Regulated vs. Deregulated A-20
Figure A-17 — Coal Steam Dataset – CAPEX for FGD/No FGD A-21
Figure A-18 — Coal Steam Dataset – O&M for FGD vs. No FGD A-22
Figure A-19 — Coal Steam Dataset – CAPEX for Bituminous/Subbituminous A-23
Figure A-20 — Coal Steam Dataset – O&M for Bituminous vs. Subbituminous A-24

TABLES AND FIGURES

Table or Figure — Page

Figure A-21 — CAPEX vs. Age for All MW Coal Plants (2017 $/MWh) A-24
Figure A-22 — O&M vs. Age for All Coal Plants (2017 $/MWh) A-25
Figure A-23 — Capacity Factor vs. Age for All Coal Plants A-25
Figure A-24 — Capacity Factor vs. Age for All Gas/Oil Steam Plants A-26
Figure B-1 — Gas/Oil Steam Dataset – CAPEX for All Plant MW Sizes B-2
Figure B-2 — Gas/Oil Steam Dataset – O&M for All Plant MW Sizes B-3
Figure B-3 — Gas/Oil Steam Dataset – CAPEX for Less than 500-MW Plant Size B-4
Figure B-4 — Gas/Oil Steam Dataset – O&M for Less than 500-MW Plant Size B-5
Figure B-5 — Gas/Oil Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size B-6
Figure B-6 — Gas/Oil Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size B-7
Figure B-7 — Gas/Oil Steam Dataset – CAPEX for Greater than 1,000-MW Plant Size B-9
Figure B-8 — Gas/Oil Steam Dataset – O&M for Greater than 1,000-MW Plant Size B-10
Figure C-1 — Gas/Oil CC Dataset – CAPEX for All Plant MW Sizes C-2
Figure C-2 — Gas/Oil CC Dataset – O&M for All Plant MW Sizes C-3
Figure C-3 — Gas/Oil CC Dataset – CAPEX for Less than 500-MW Plant Size C-4
Figure C-4 — Gas/Oil CC Dataset – O&M for Less than 500-MW Plant Size C-5
Figure C-5 — Gas/Oil CC Dataset – CAPEX for 500-MW to 1,000-MW Plant Size C-7
Figure C-6 — Gas/Oil CC Dataset – O&M for 500-MW to 1,000-MW Plant Size C-8
Figure C-7 — Gas/Oil CC Dataset – CAPEX for Greater than 1,000-MW Plant Size C-9
Figure C-8 — Gas/Oil CC Dataset – O&M for Greater than 1,000 MW Plant Size C-10
Figure C-9 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor < 50% C-11
Figure C-10 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor < 50% C-12
Figure C-11 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor > 50% C-14
Figure C-12 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor > 50% C-15
Figure D-1 — Gas/Oil CT Dataset – CAPEX for All Plant MW Sizes D-2
Figure D-2 — Gas/Oil CT Dataset – O&M for All Plant MW Sizes D-3
Figure D-3 — Gas/Oil CT Dataset – CAPEX for Less than 100-MW Plant Size D-4
Figure D-4 — Gas/Oil CT Dataset – O&M for Less than 100-MW Plant Size D-5
Figure D-5 — Gas/Oil CT Dataset – CAPEX for Between 100-MW and 300-MW Plant Size D-7
Figure D-6 — Gas/Oil CT Dataset – O&M for Between 100-MW and 300-MW Plant Size D-8
Figure D-7 — Gas/Oil CT Dataset – CAPEX for Greater than 300-MW Plant Size D-9
Figure D-8 — Gas/Oil CT Dataset – O&M for Greater than 300-MW Plant Size D-10

TABLES AND FIGURES

Table or Figure — Page

Figure E-1 — Conventional Hydroelectric Dataset – CAPEX for All MW Plant Sizes E-2
Figure E-2 — Conventional Hydroelectric – O&M for All MW Plant Sizes E-3
Figure F-1 — Pumped Hydroelectric Dataset – CAPEX for All MW Plant Sizes F-2
Figure F-2 — Pumped Hydroelectric – O&M for All Plant MW Sizes F-3
Figure G-1 — Solar PV Dataset – CAPEX for All MW Plant Sizes G-3
Figure G-2 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (< 5 MW) G-5
Figure G-3 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (> 5 MW) G-6
Figure G-4 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (< 5 MW) G-6
Figure G-5 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (> 5 MW) G-7
Figure G-6 — Annual Site O&M Cost per MWh vs. Age of Project G-7
Figure G-7 — Annual Site O&M Cost per kW-Year Capacity vs. Age of Project G-8
Figure I-1 — Geothermal Dataset – CAPEX for All MW Plant Sizes I-2
Figure I-2 — Geothermal Dataset – O&M for All MW Plant Sizes I-3
Figure J-1 — Wind Dataset – CAPEX for All MW Plant Sizes J-2
Figure J-2 — Wind Dataset – CAPEX for 0-100-MW Plant Sizes J-4
Figure J-3 — Wind Dataset – CAPEX for 100-200-MW Plant Sizes J-5
Figure J-4 — Wind Dataset – CAPEX for Greater than 200-MW Plant Sizes J-7
Figure J-5 — Wind Dataset – O&M for All MW Plant Sizes J-8
Figure J-6 — Wind Dataset – O&M for 0-100-MW Plant Sizes J-9
Figure J-7 — Wind Dataset – O&M for 100-200-MW Plant Sizes J-10
Figure J-8 — Wind Dataset – O&M for Plant Sizes Greater than 200 MW J-11

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

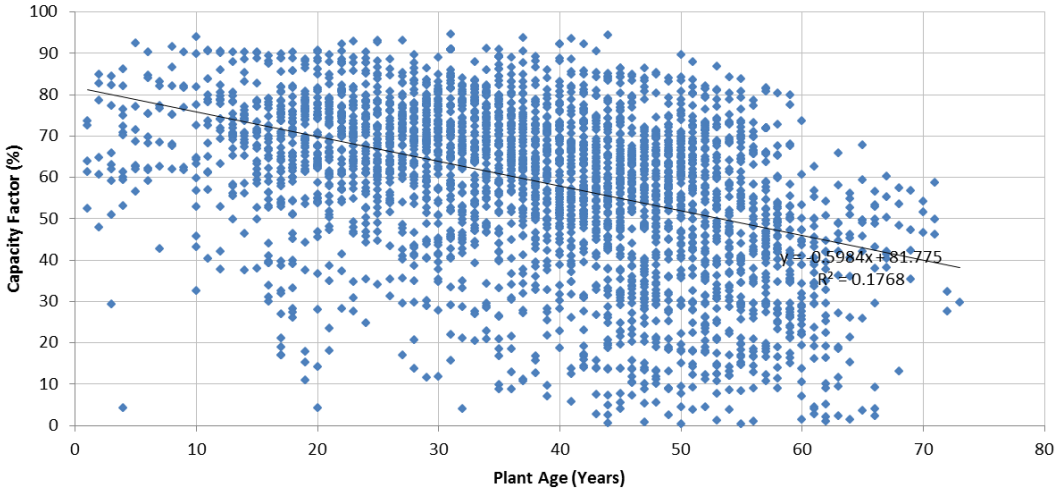
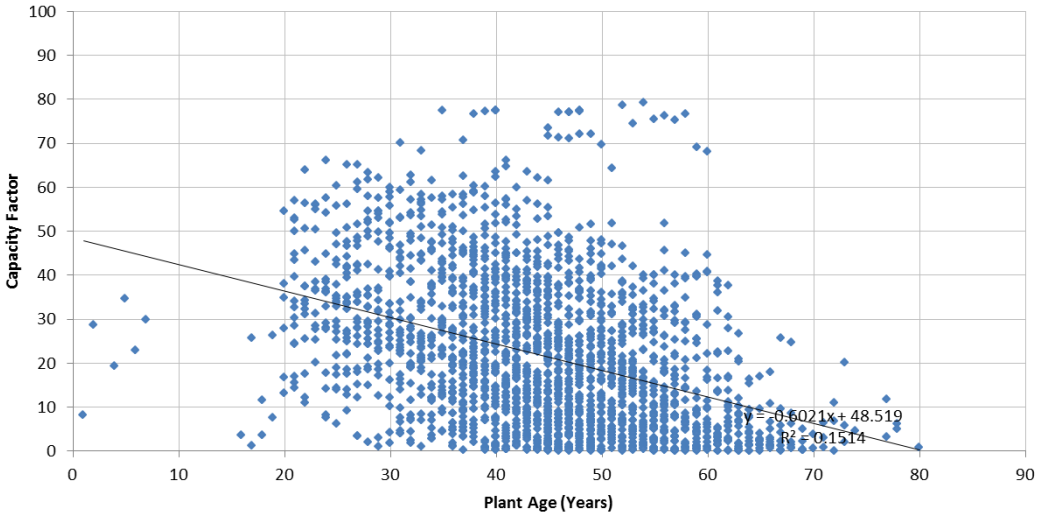


Figure ES-2 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



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
Senior Consultant

Patrick S. Daou
Consultant

Eric R. DeCristofaro
Senior Consultant

Marc E. Lemmons
Project Associate

Sean P. Noonan
Senior Consultant

Ryan M. Swanson
Senior Consultant

John R. Wroble
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.

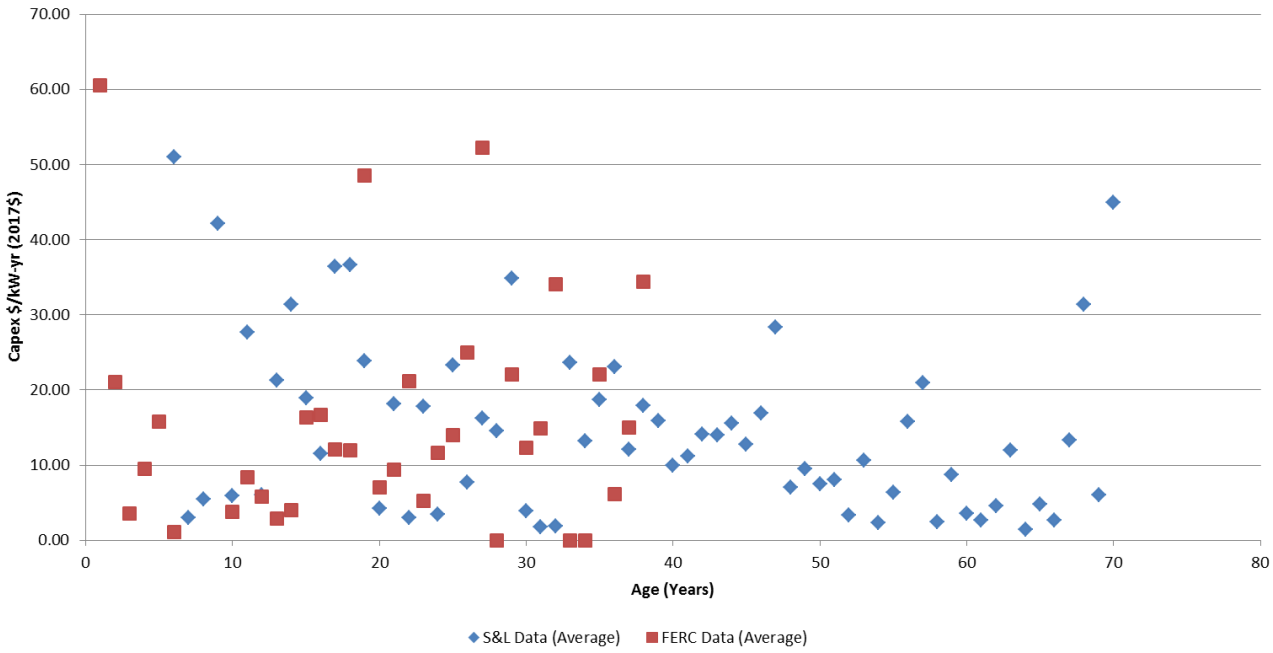
2.5 STATISTICAL TESTS

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



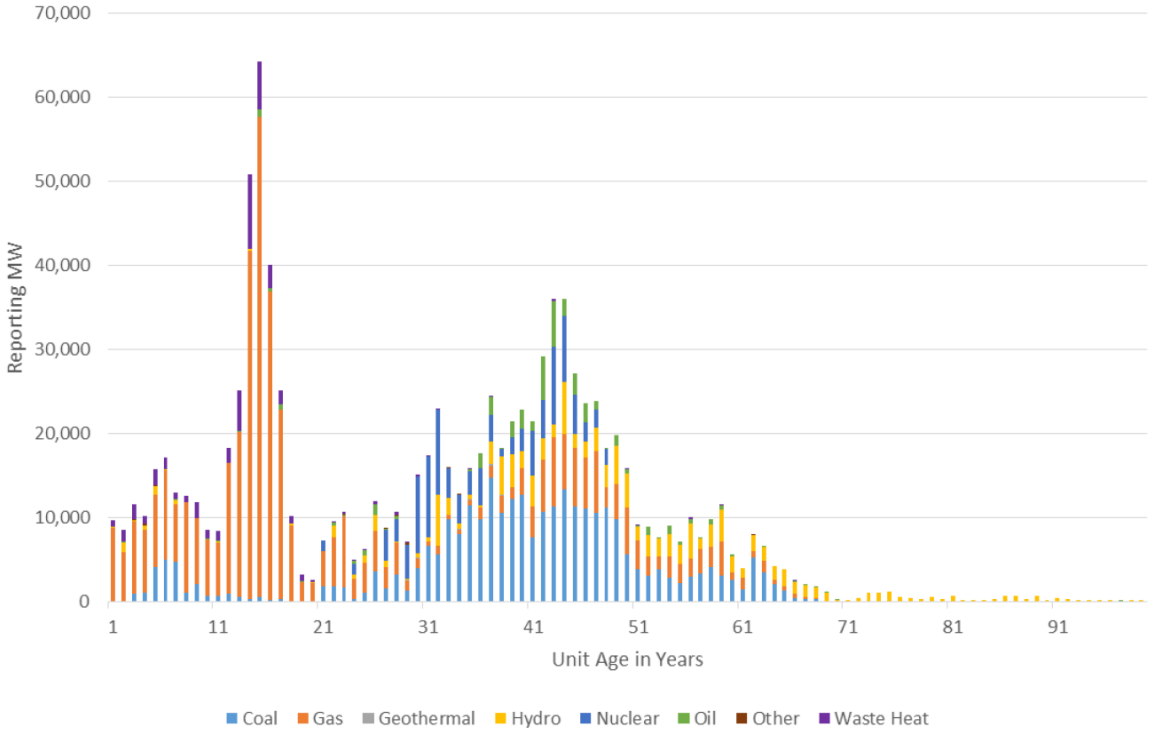
As discussed in Section 0, CAPEX spending for coal plants does not follow a uniform pattern for all plants. For example, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

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.

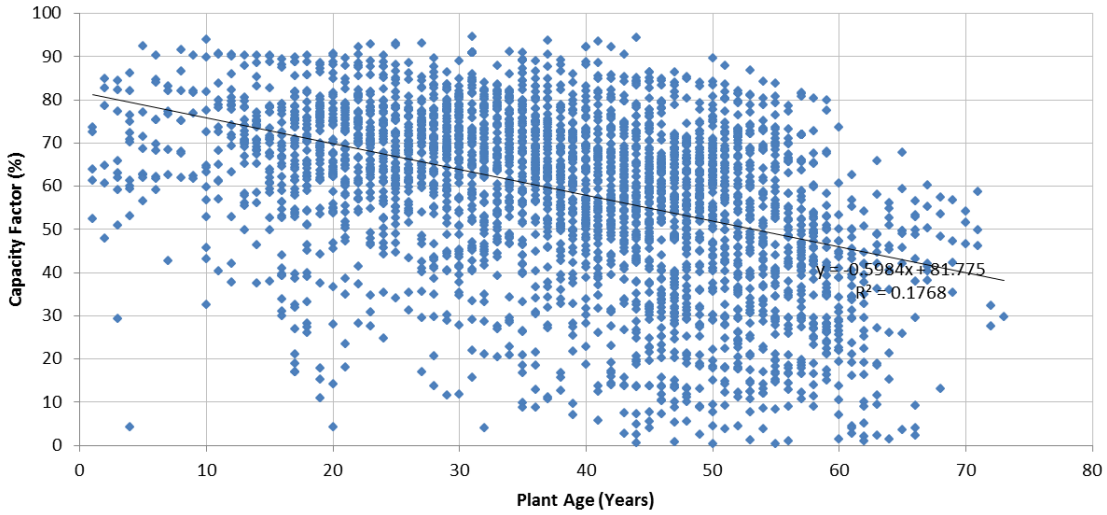
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- 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.

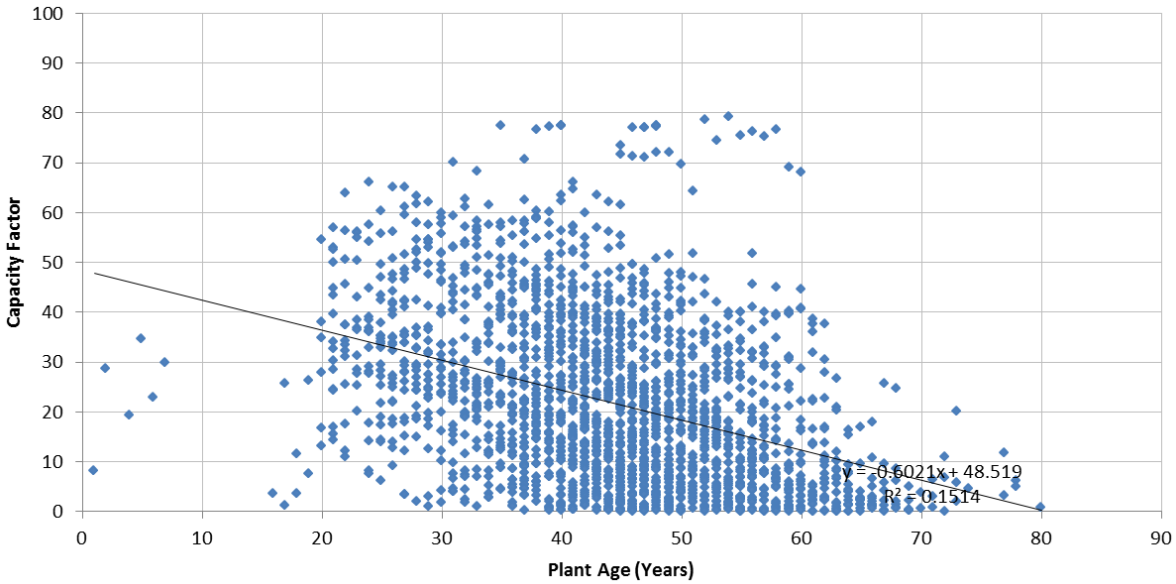
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- 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

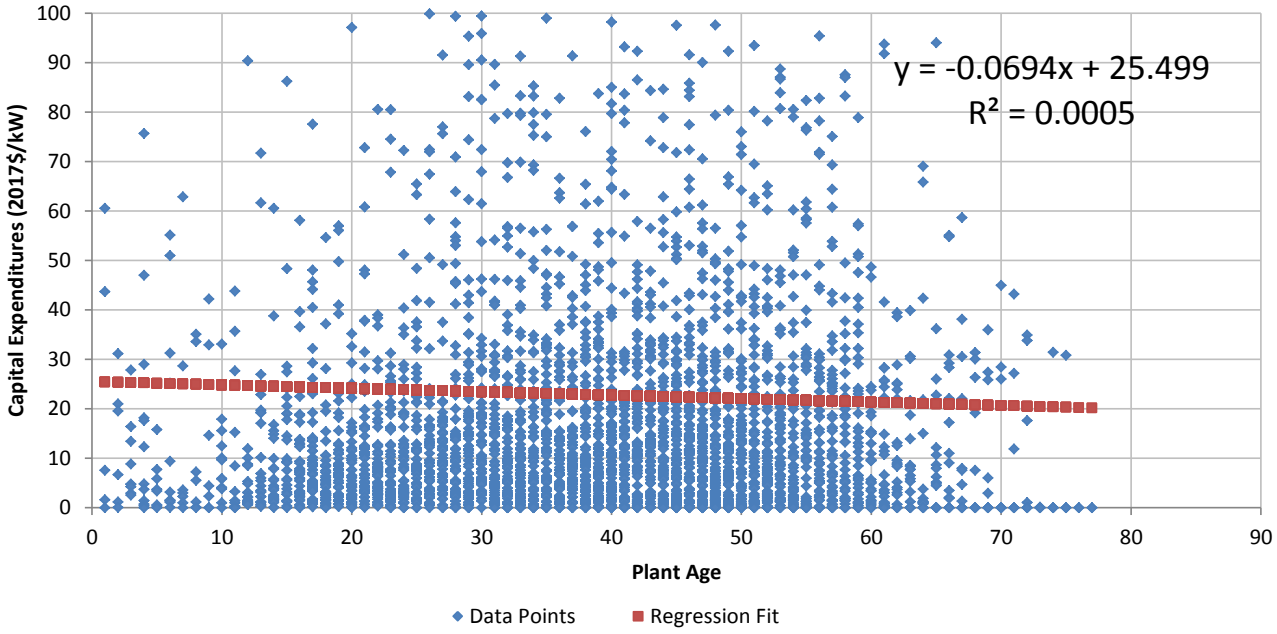
CAPITAL EXPENDITURES – ALL PLANT SIZES

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.

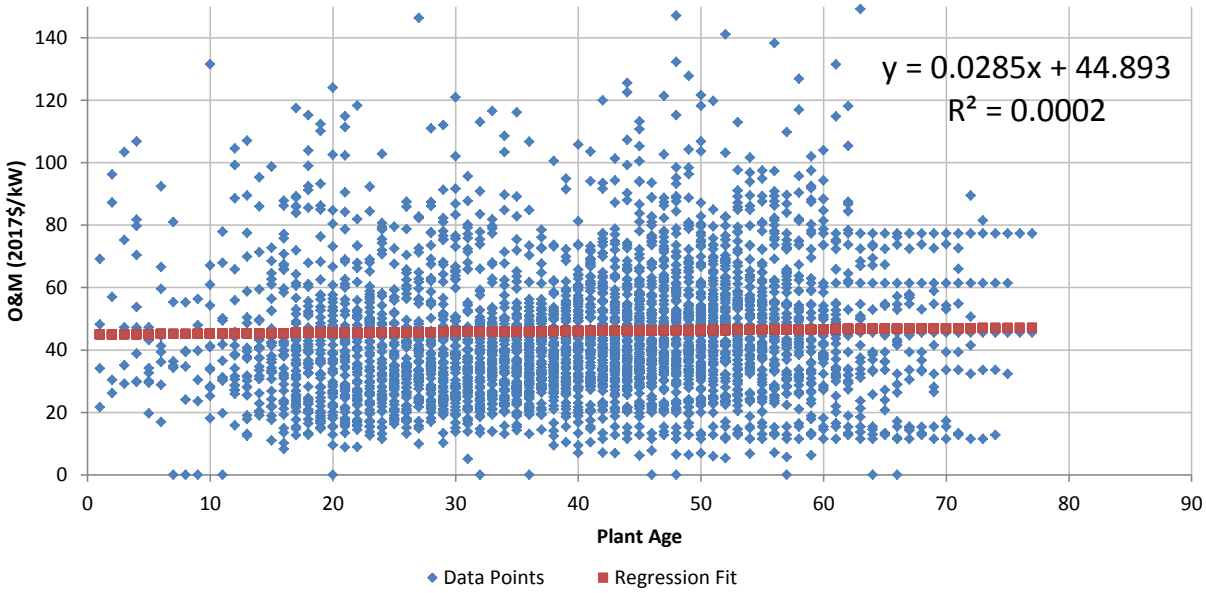
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

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.

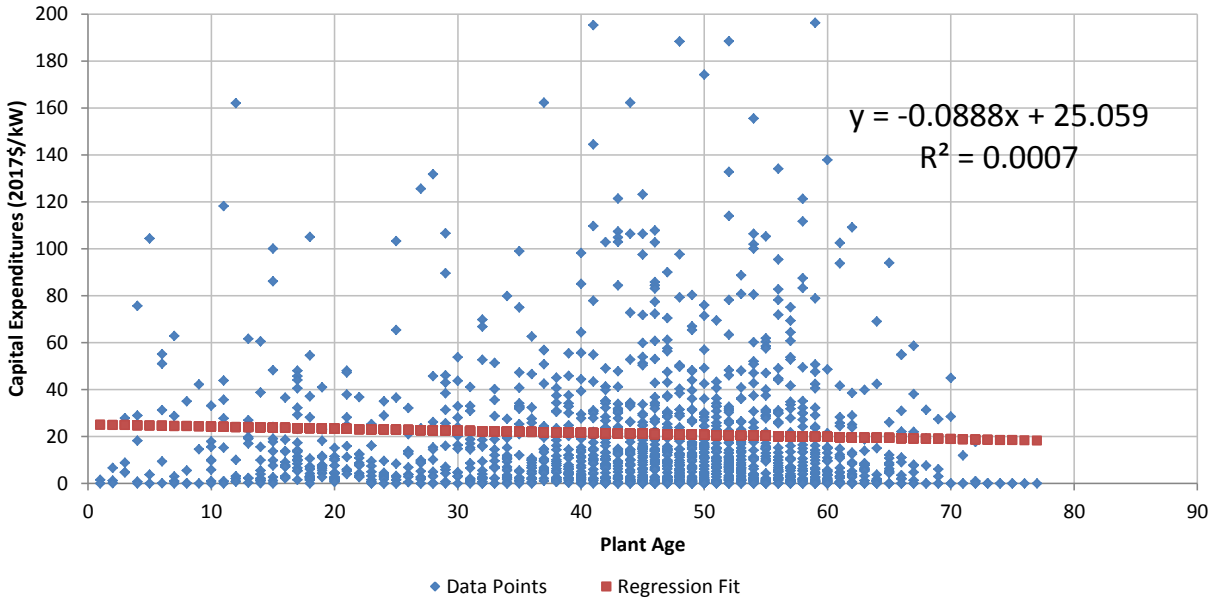
CAPITAL EXPENDITURES – LESS THAN 500 MW

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

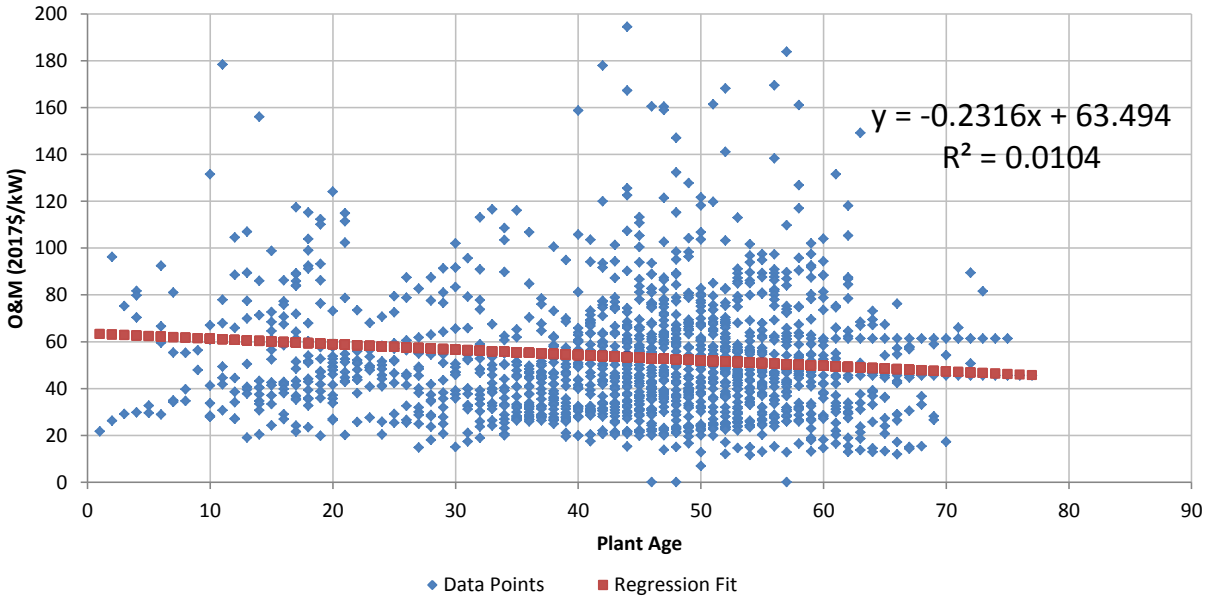
The results of the regression analysis of O&M spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear 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.

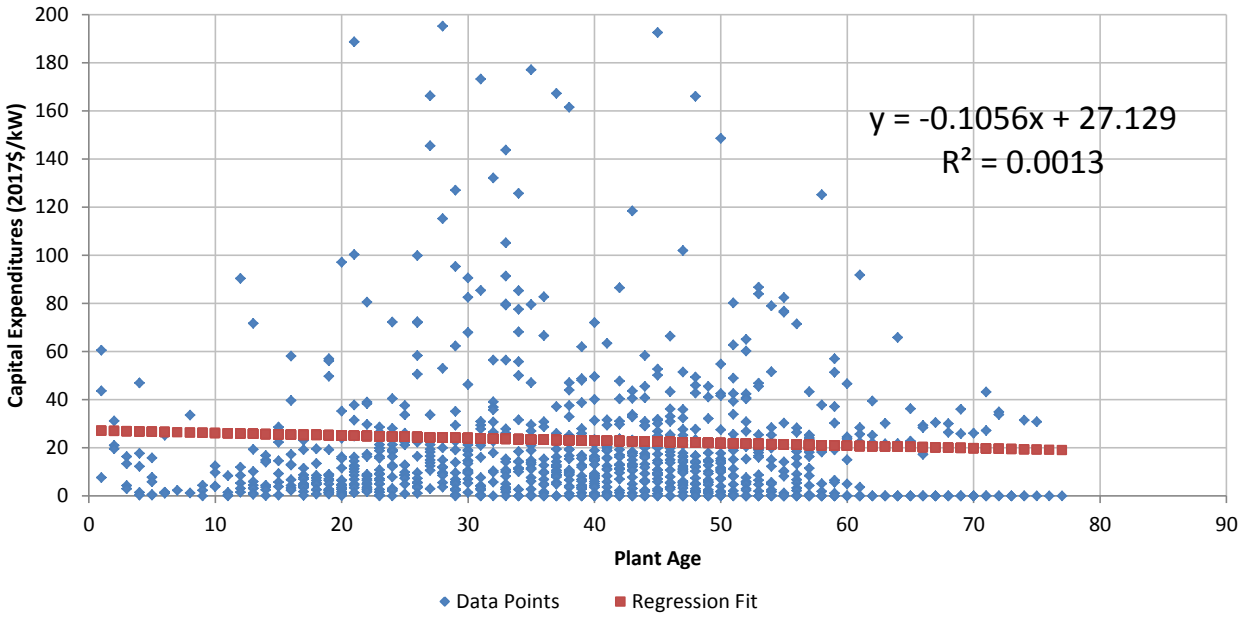
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

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

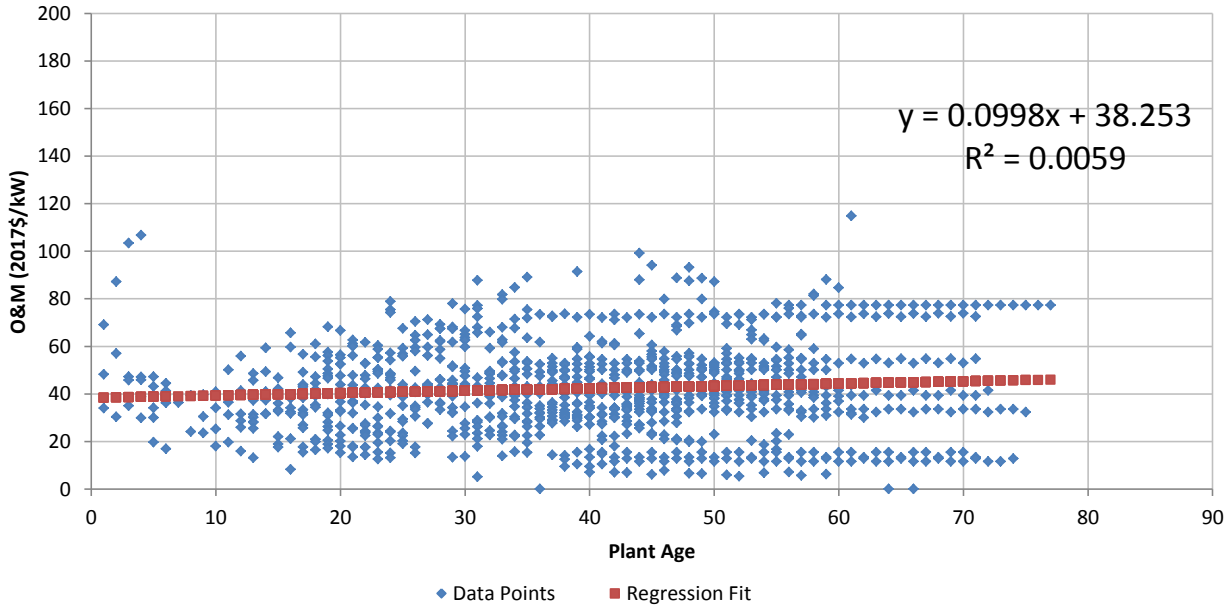
The results of the linear regression analysis of O&M spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX 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.

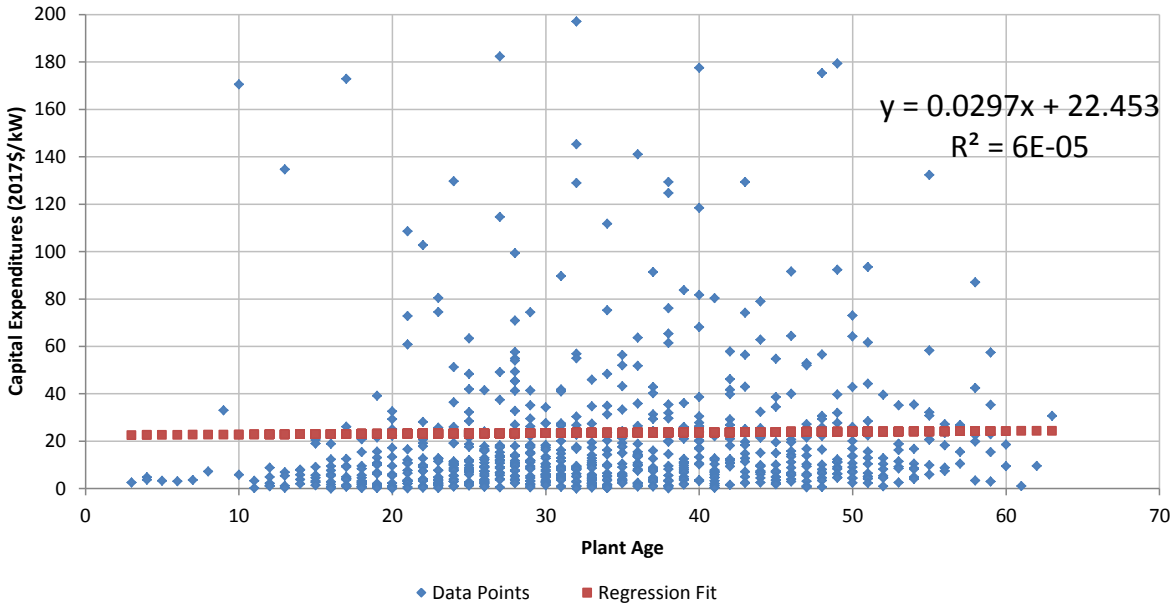
CAPITAL EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

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

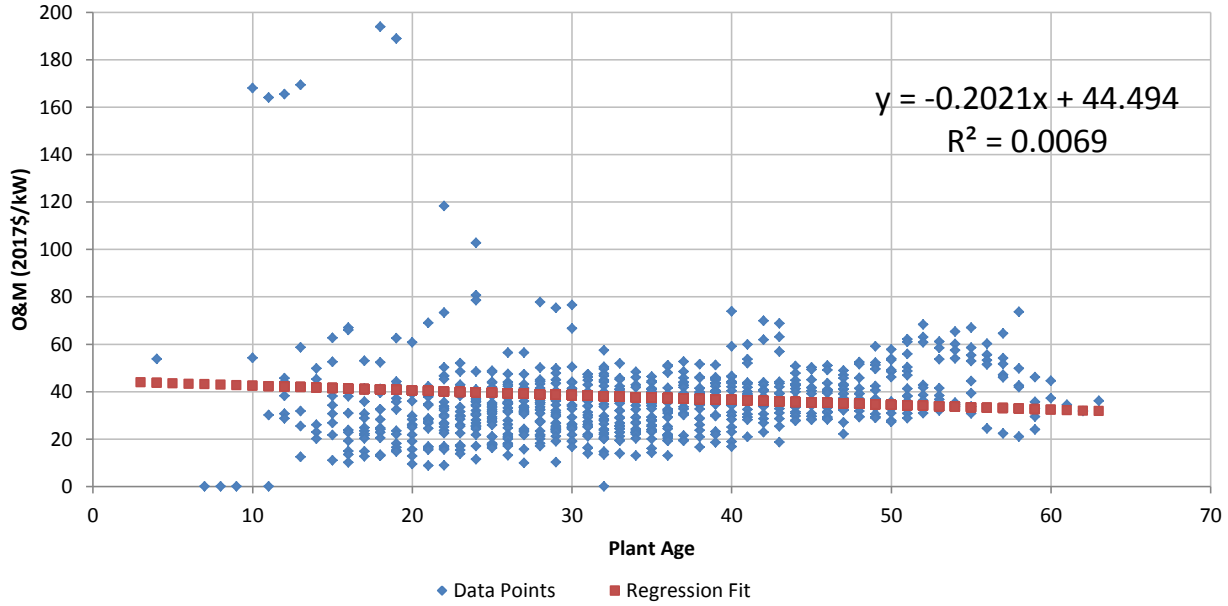
The results of the regression analysis of O&M spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (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.

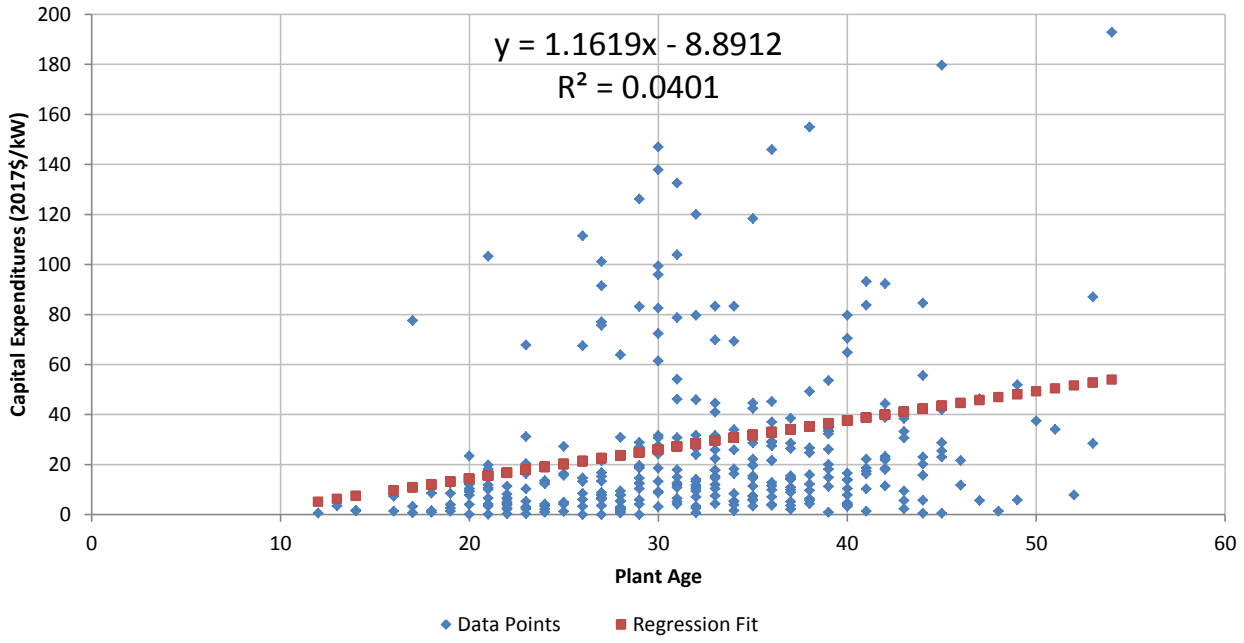
CAPITAL EXPENDITURES – GREATER THAN 2,000 MW

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



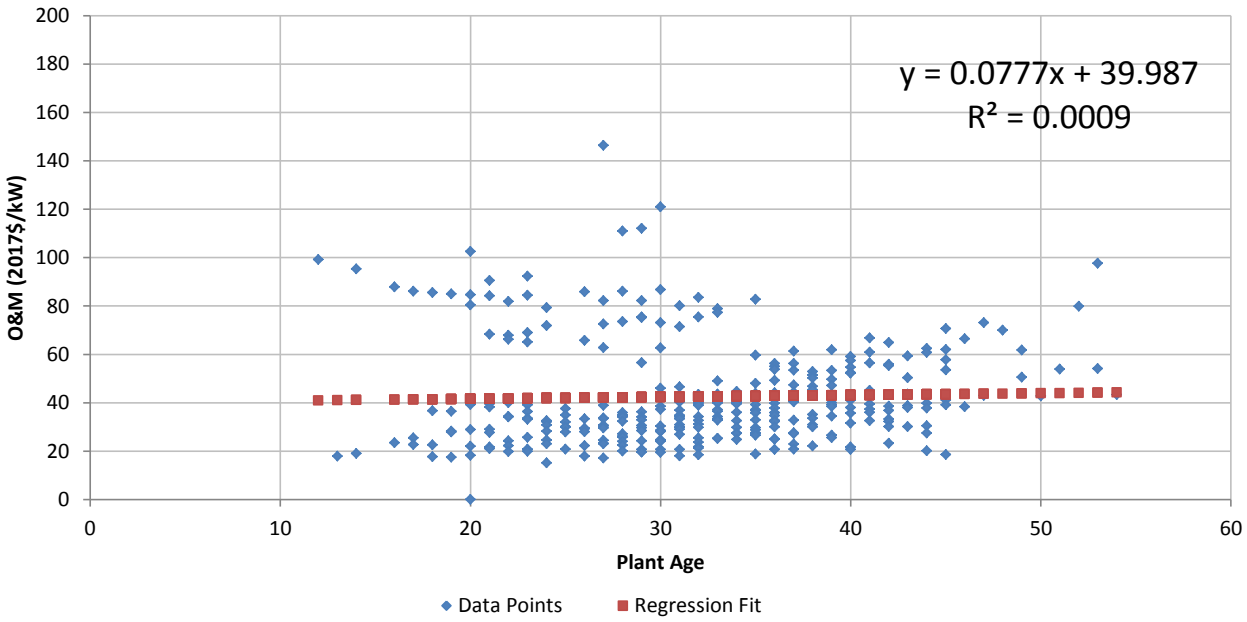
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 2,000 MW

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.

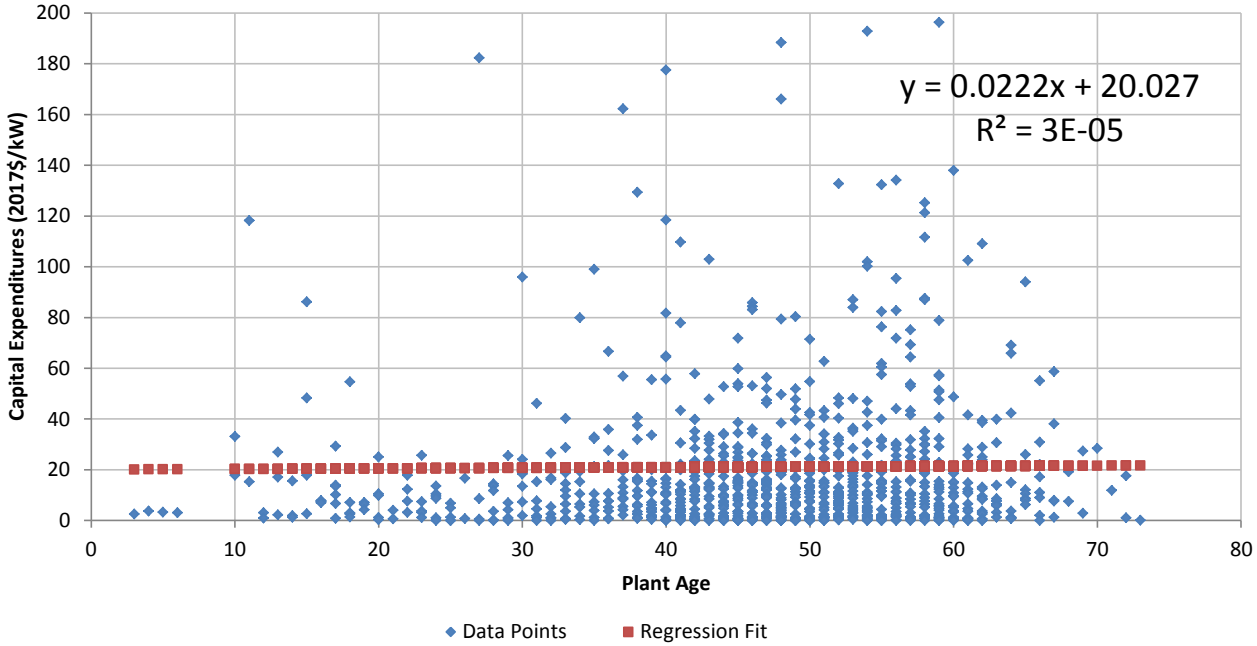
CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

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.

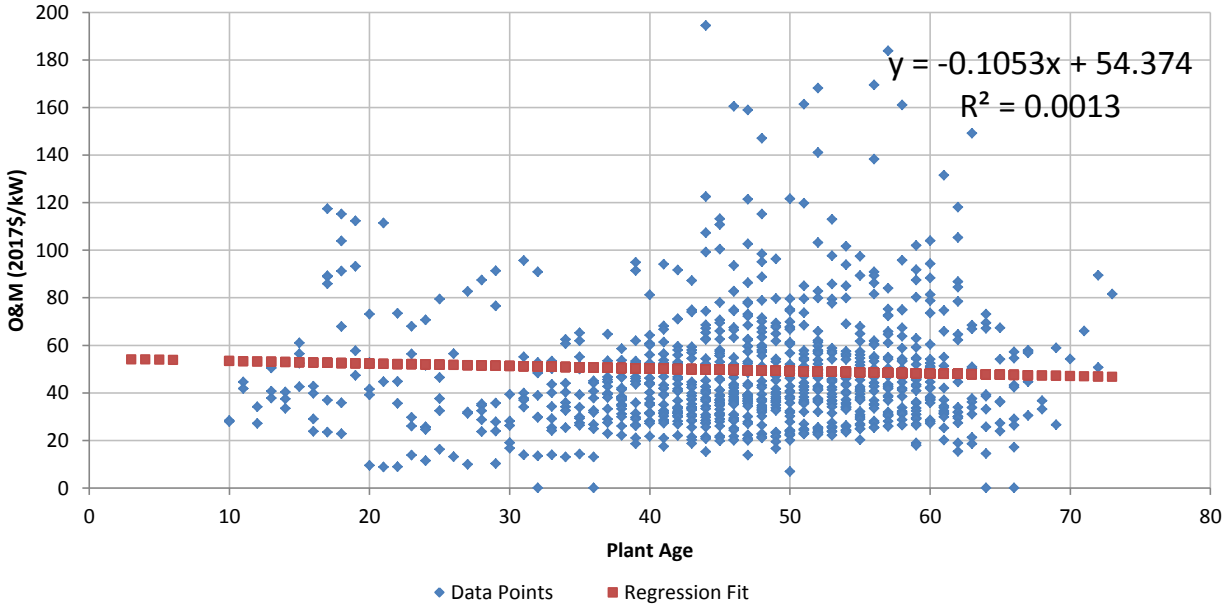
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

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.

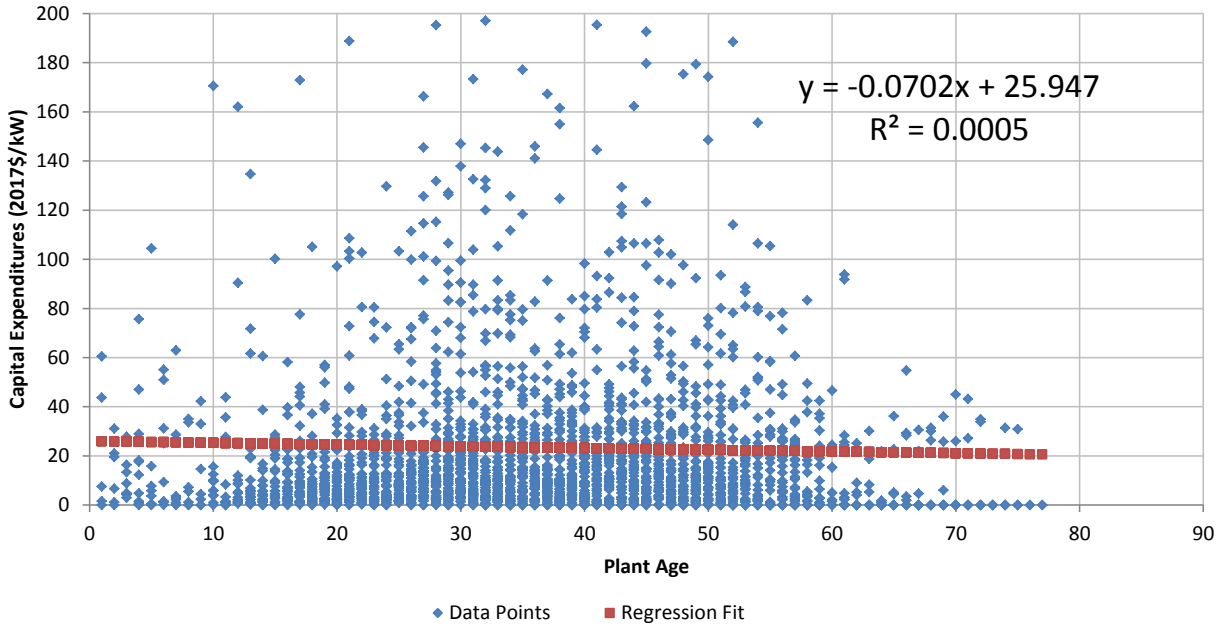
CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

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.

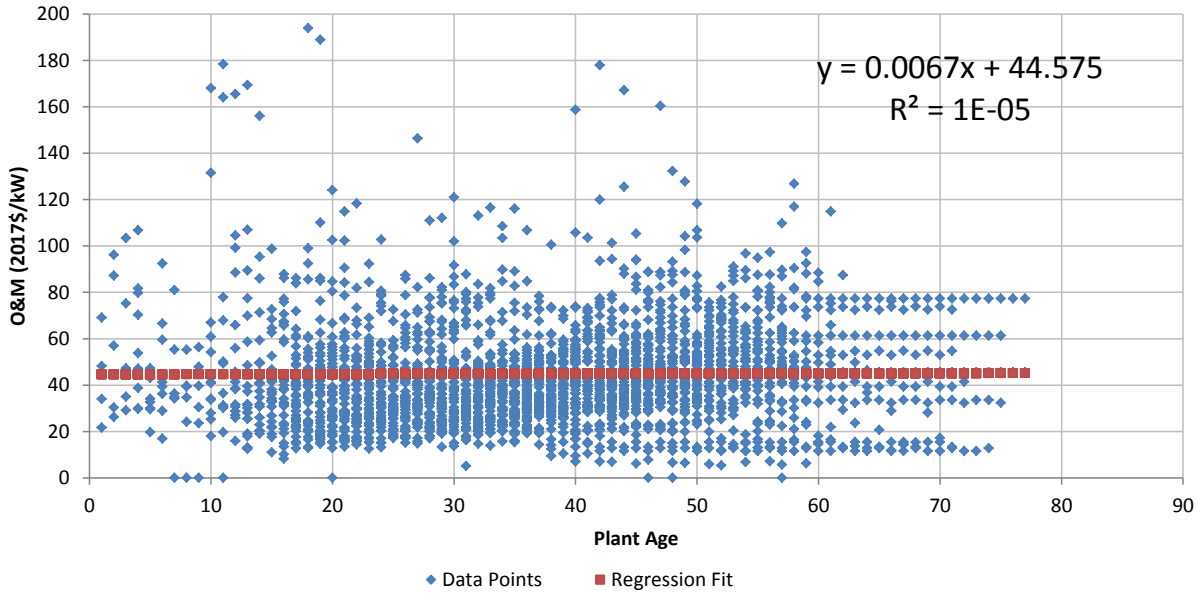
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

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.

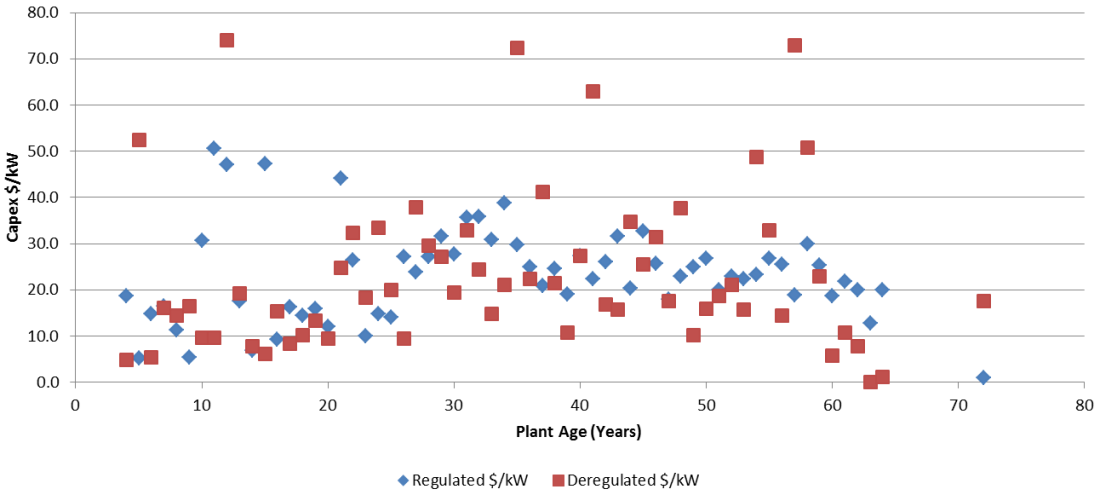
CAPITAL EXPENDITURES – REGULATED VS. DEREGULATED

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

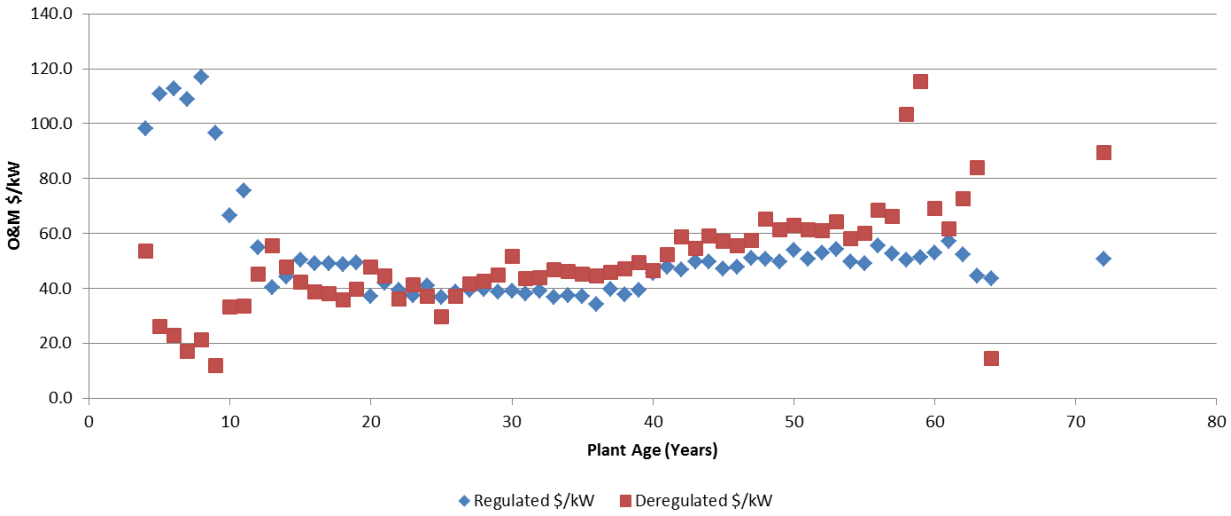
Figure A-15 — Coal Steam Dataset – CAPEX for Regulated/Deregulated



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

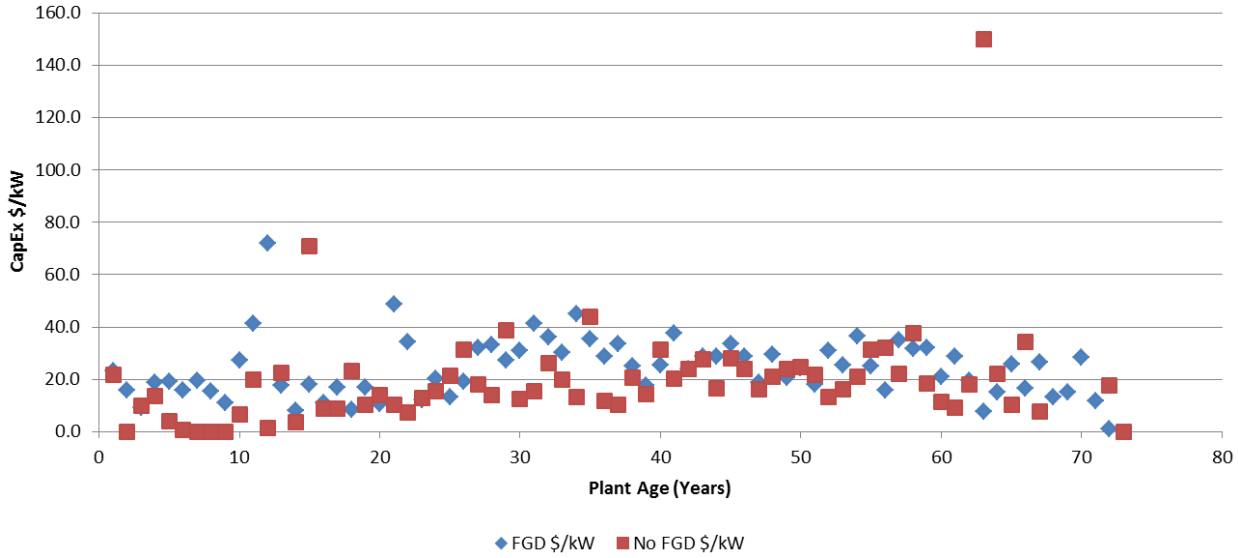
The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) with and without FGD are summarized in the table below. The p-value for the age ("slope") coefficient is slightly greater than 0.05 (nearly statistically significant) while the p-value for the 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

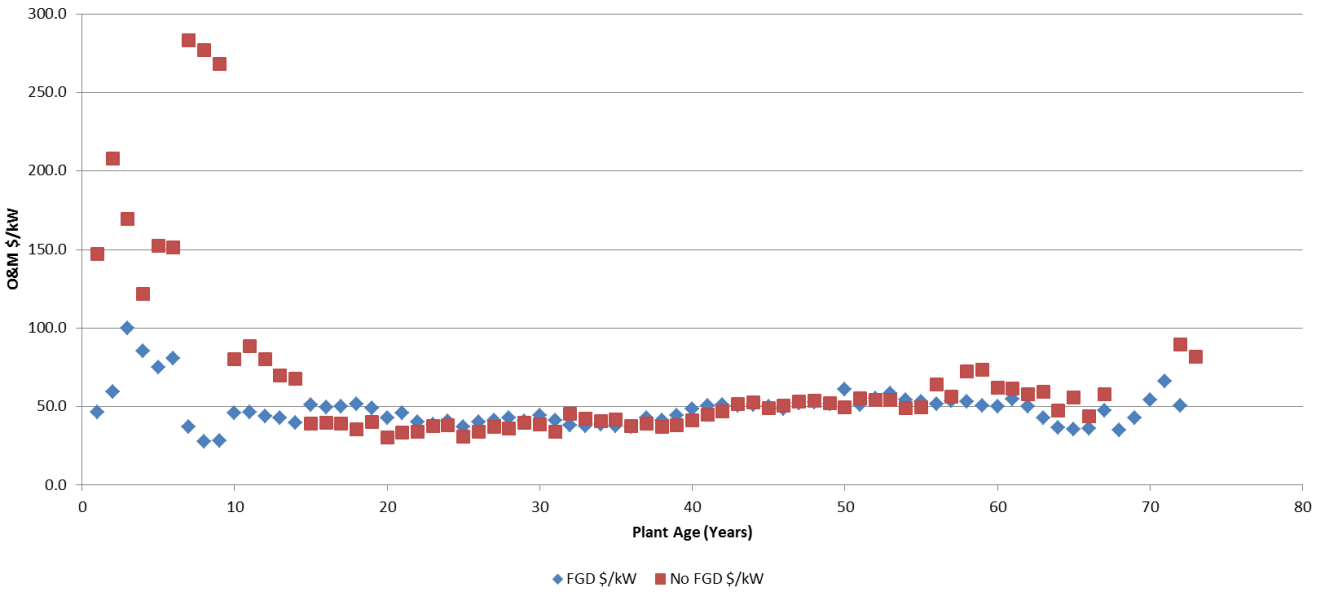
Figure A-17 — Coal Steam Dataset – CAPEX for FGD/No FGD



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



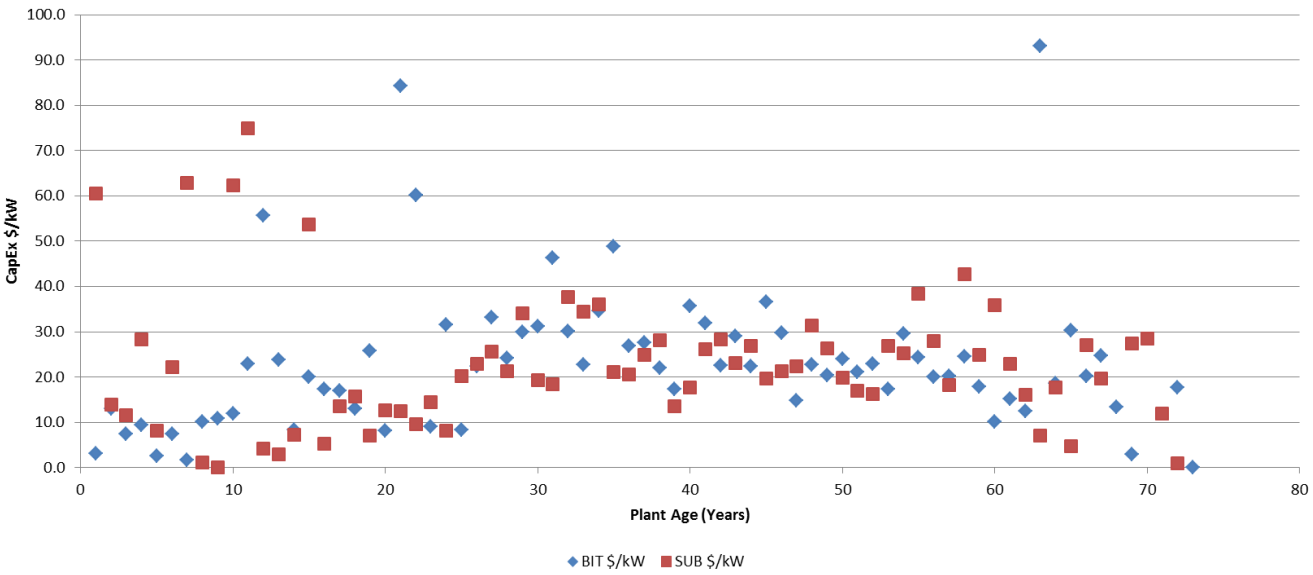
CAPITAL EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

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

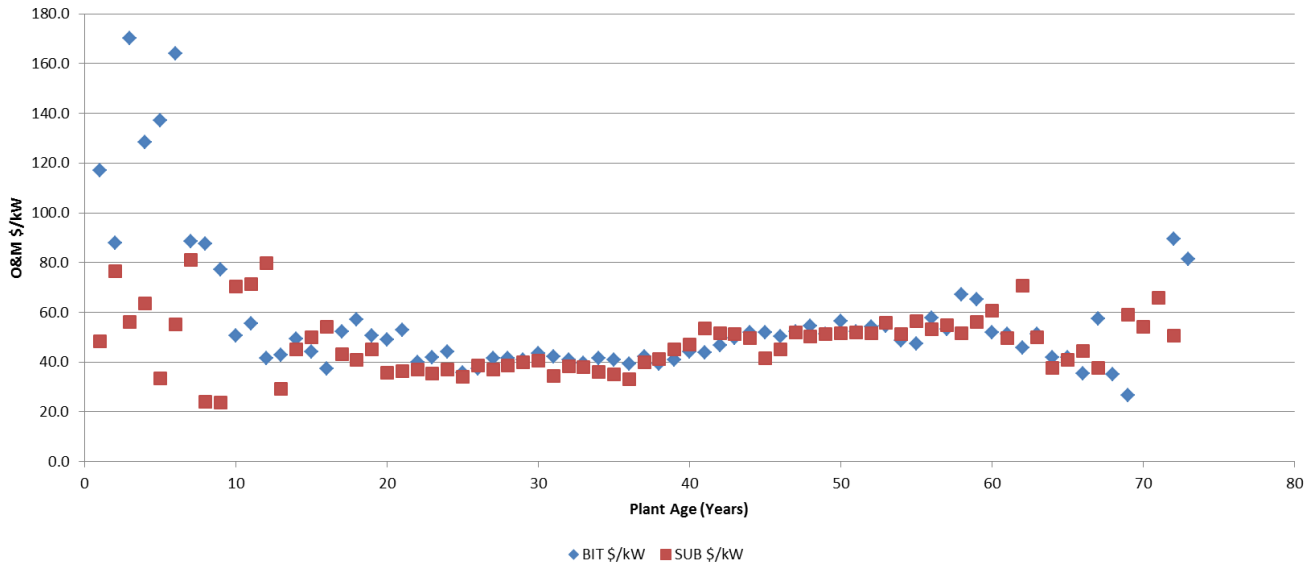
Figure A-19 — Coal Steam Dataset – CAPEX for Bituminous/Subbituminous



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)

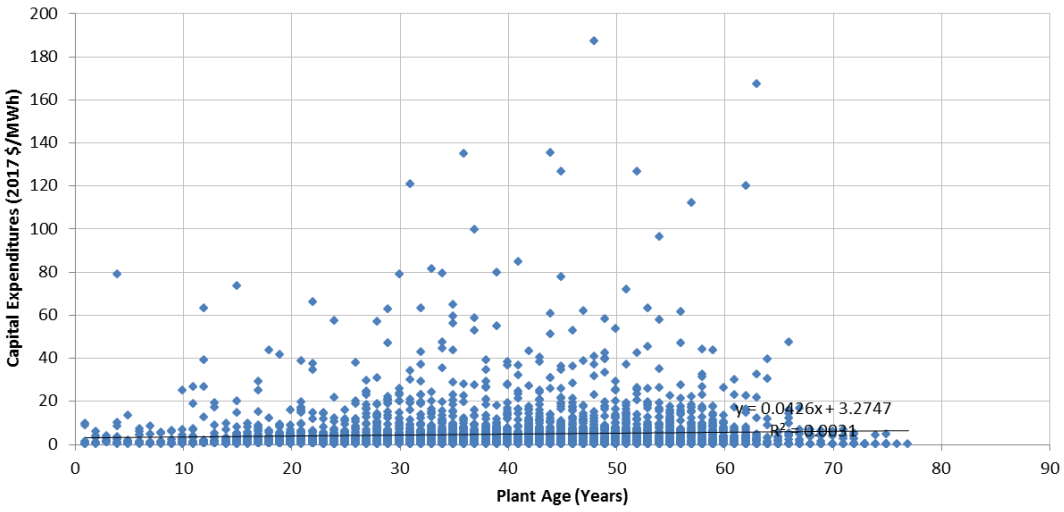
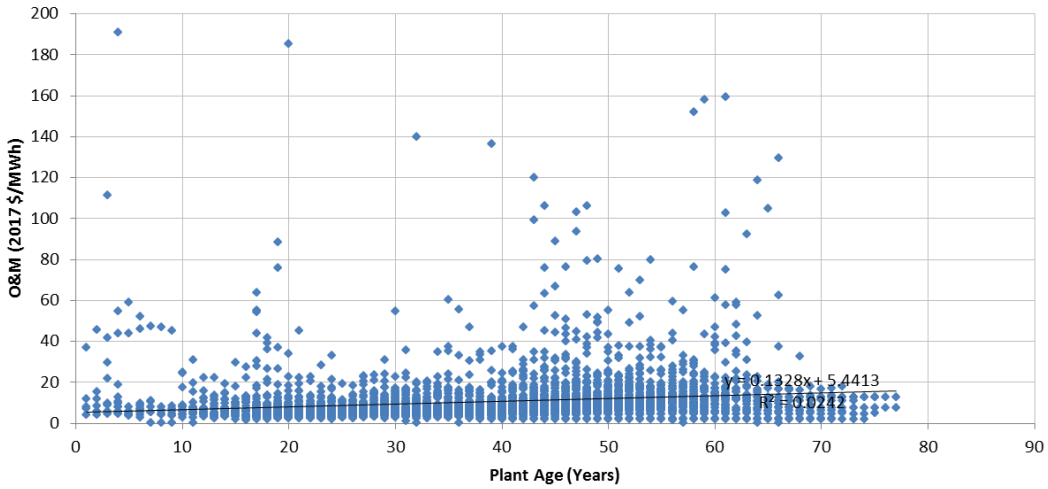


Figure A-22 — O&M vs. Age for All Coal Plants (2017 $/MWh)



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

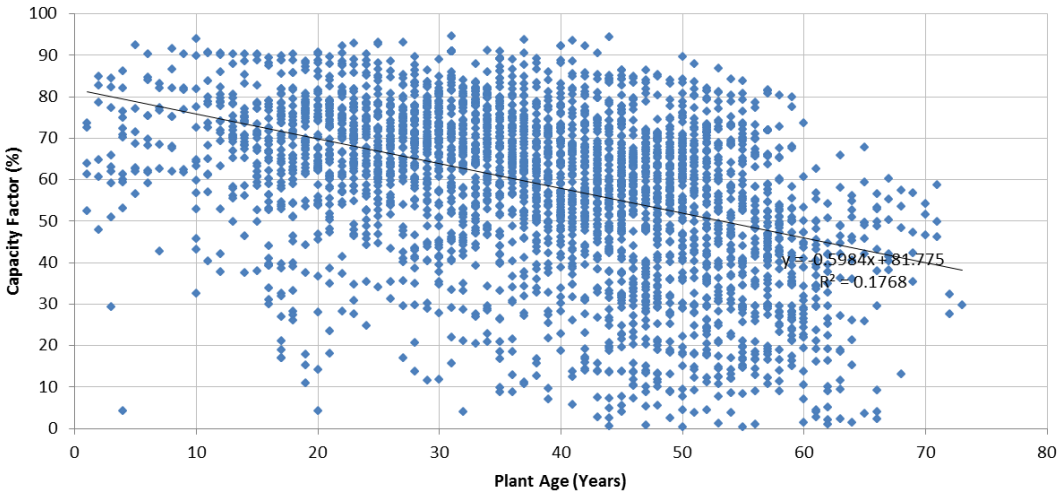
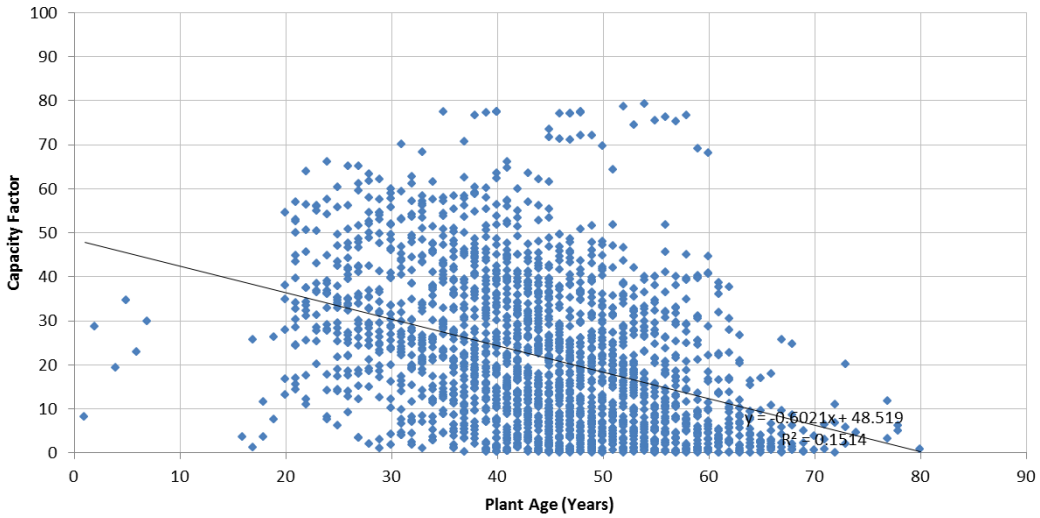


Figure A-24 — Capacity Factor vs. Age for All Gas/Oil Steam Plants





Appendix B. Regression Analysis – Gas/Oil Steam

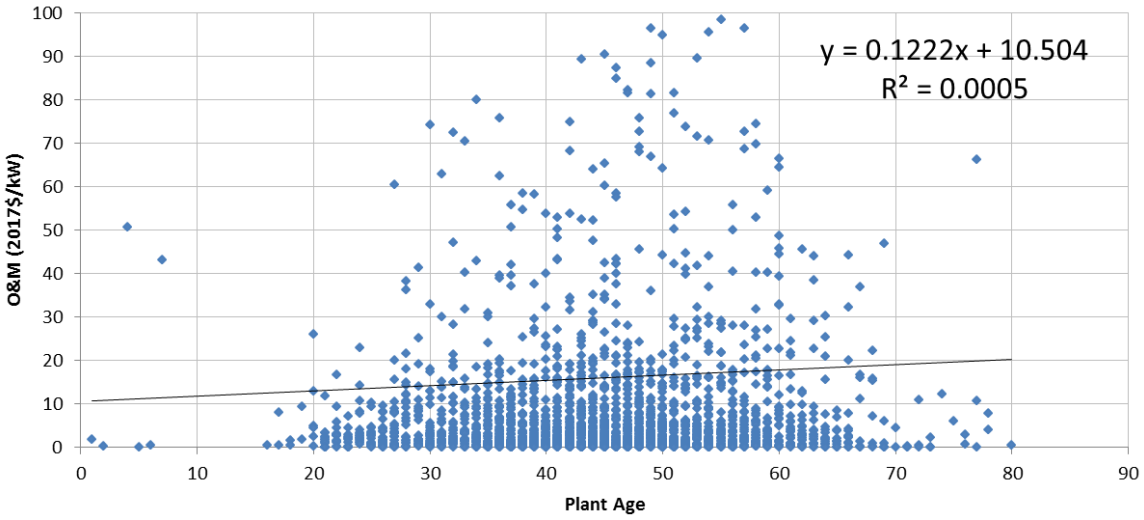
CAPITAL EXPENDITURES – ALL PLANT SIZES

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.

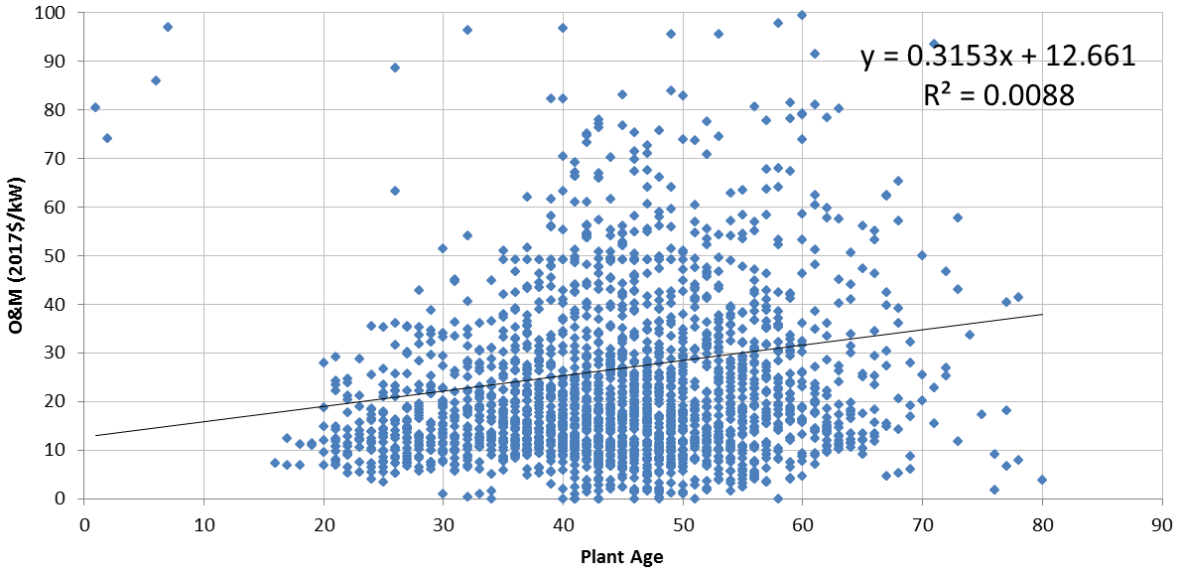
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

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.

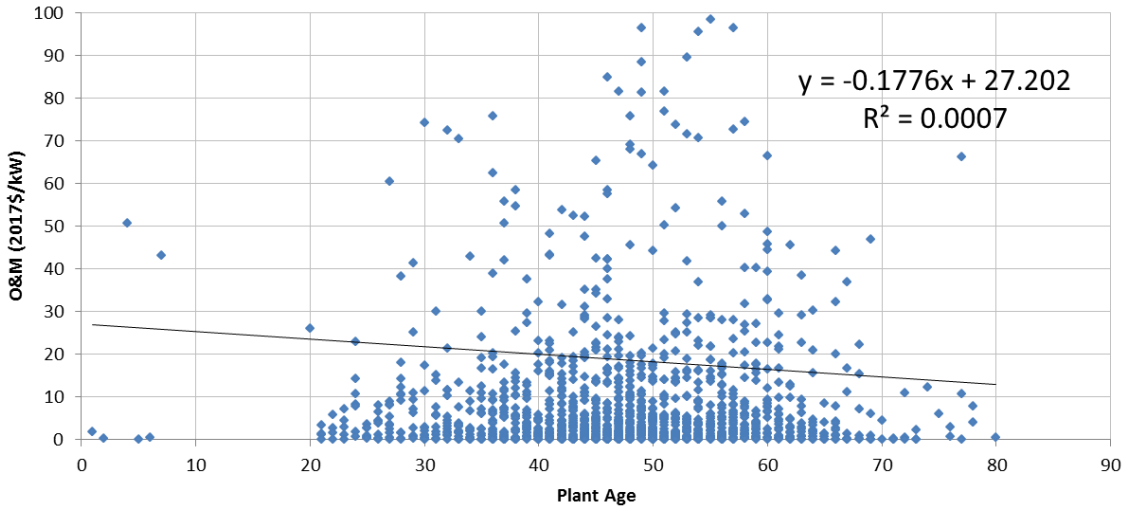
CAPITAL EXPENDITURES – LESS THAN 500 MW

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.

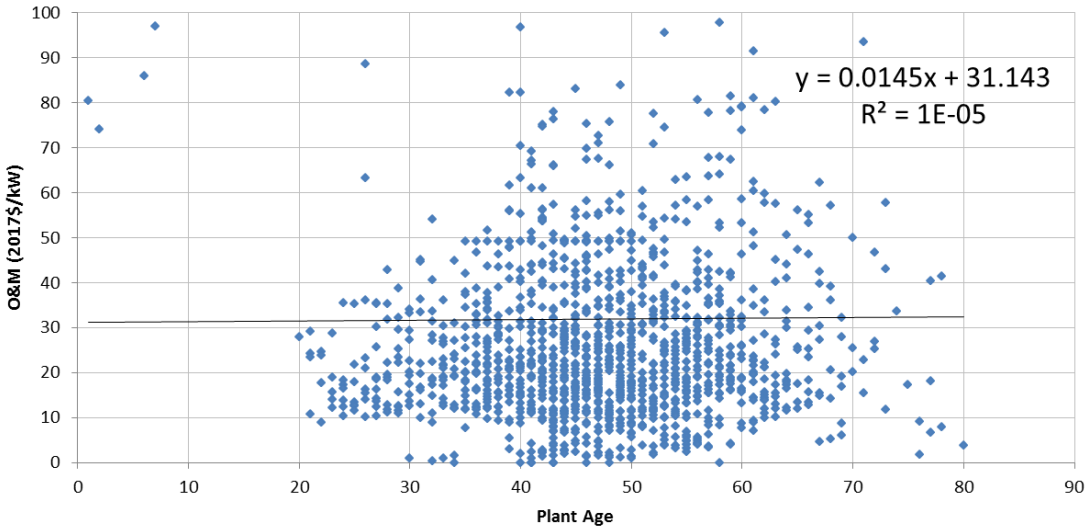
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

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.

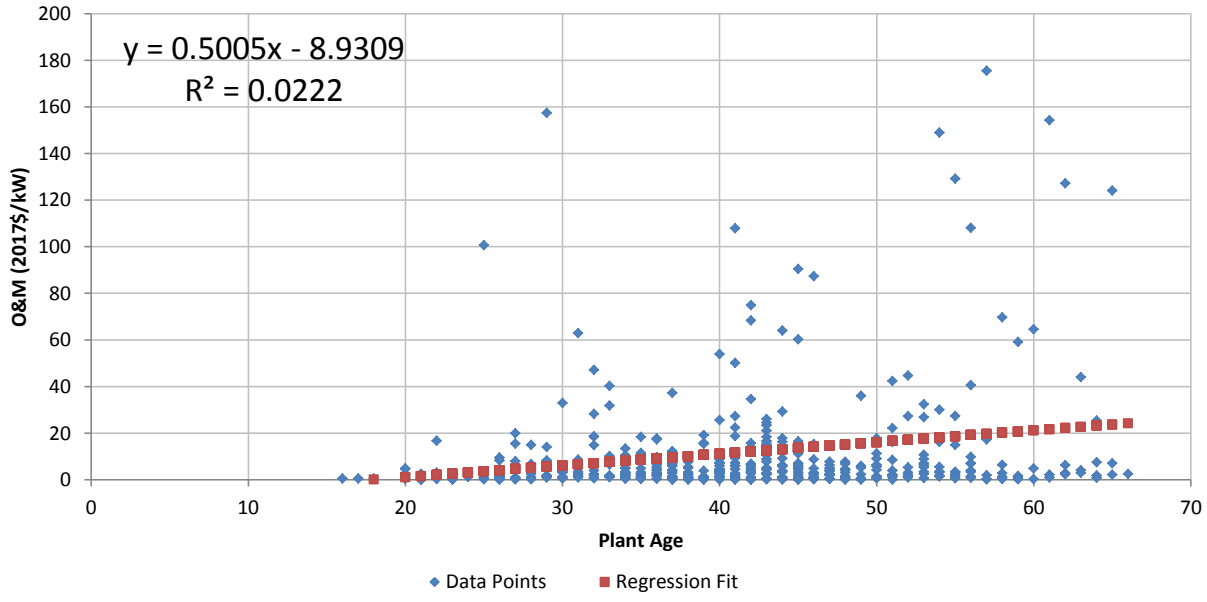
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

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



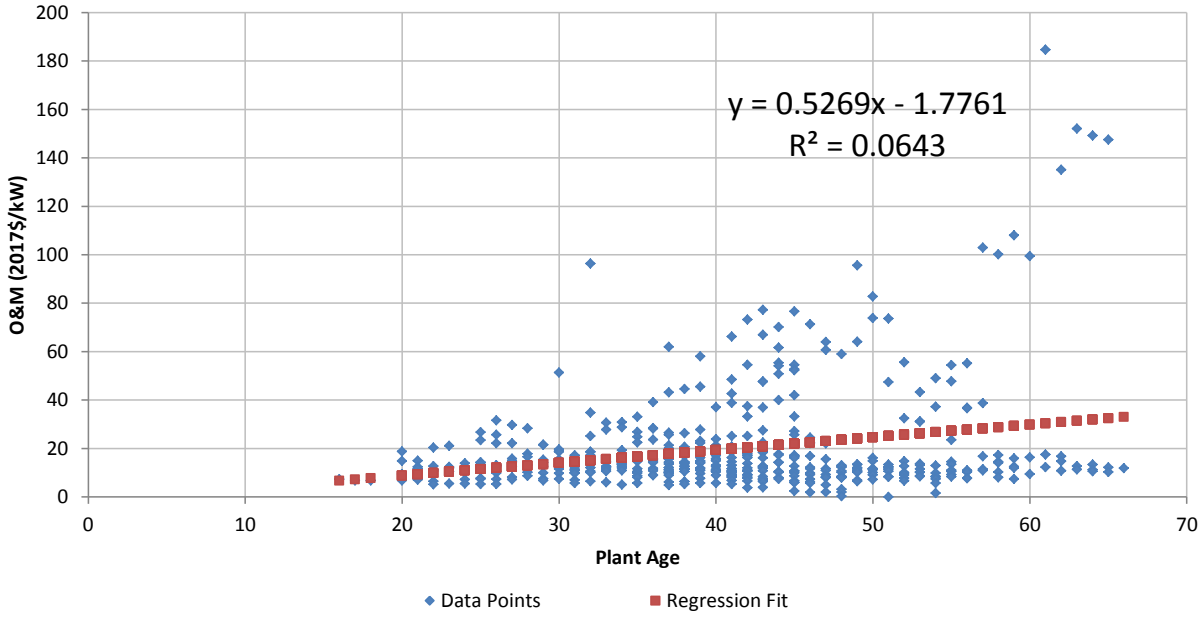
OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

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.

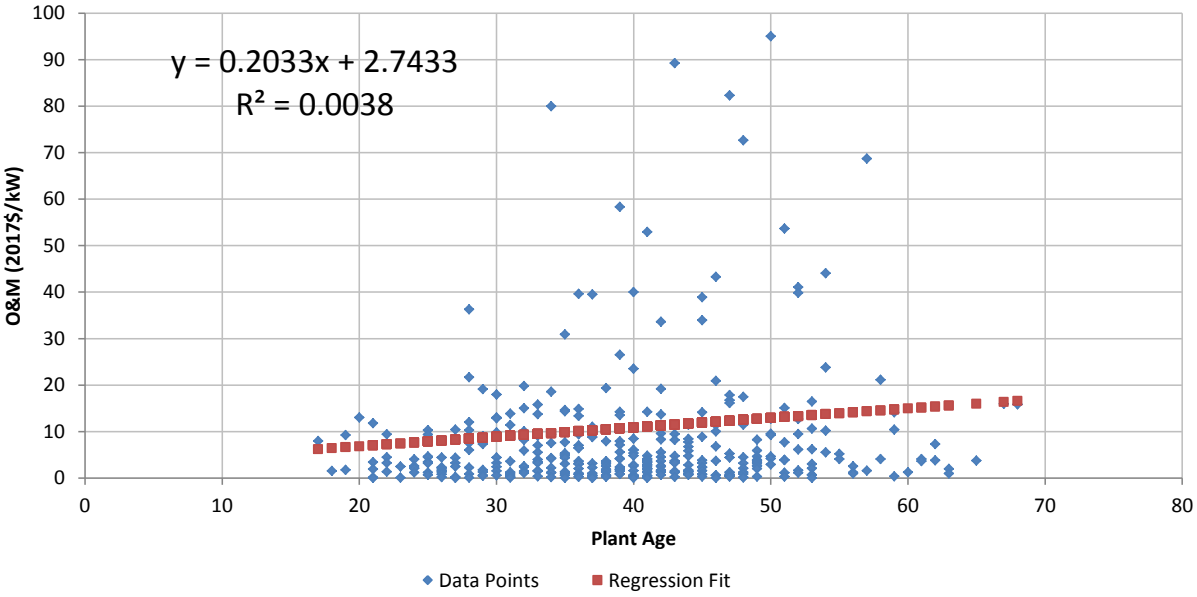
CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

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.

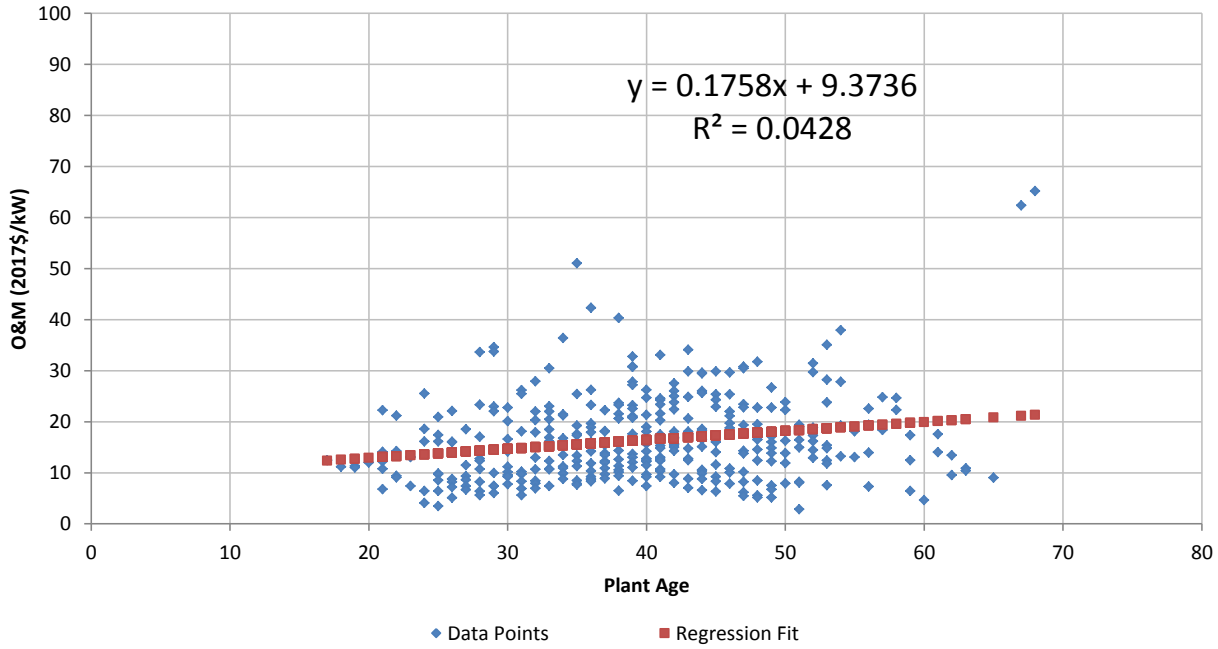
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

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

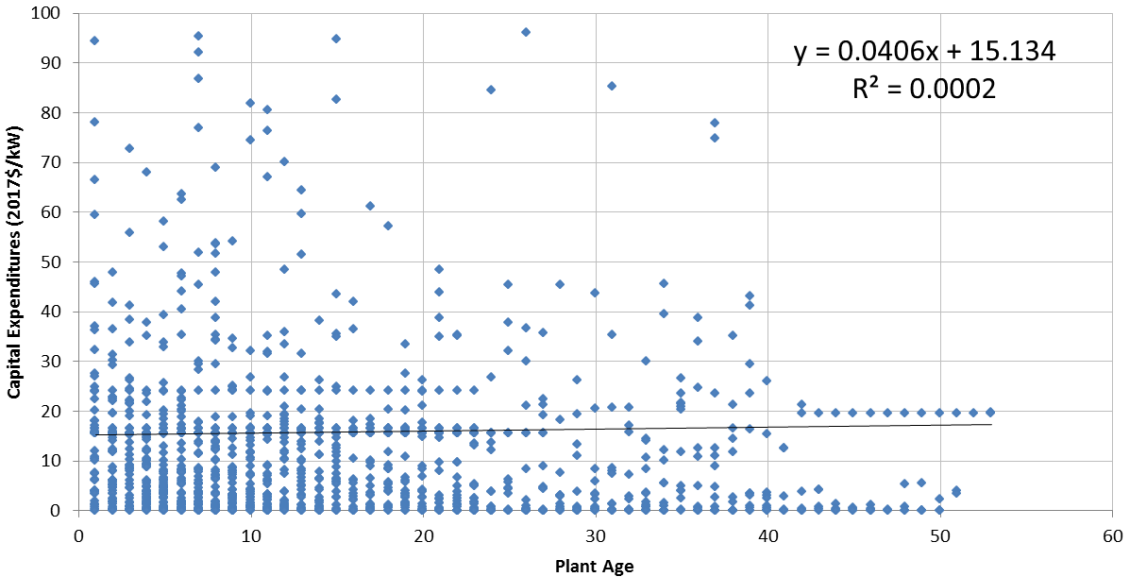
CAPITAL EXPENDITURES – ALL PLANT SIZES

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.

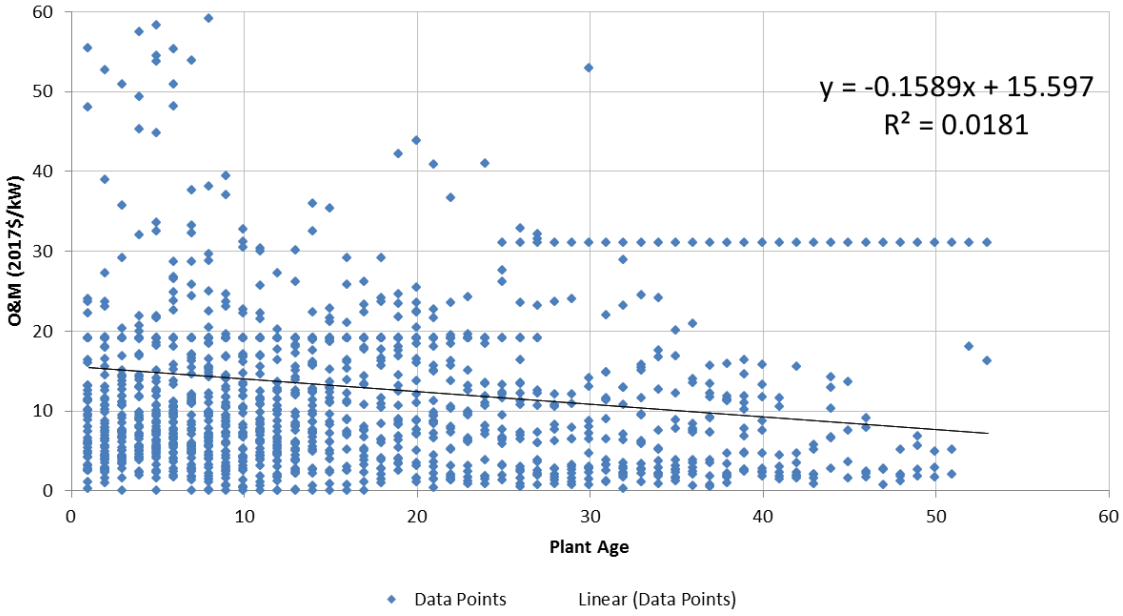
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

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.

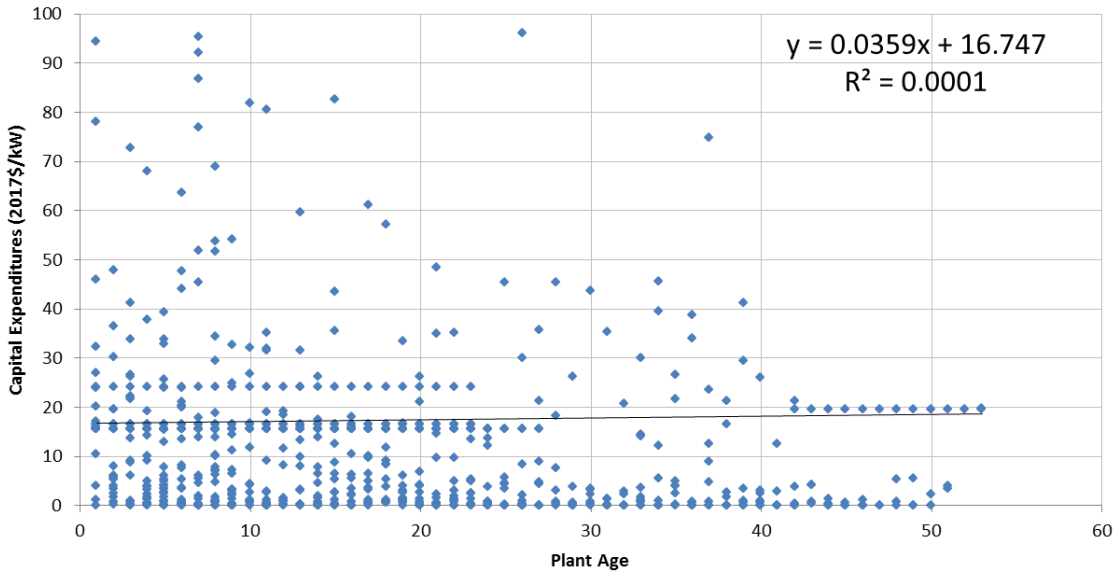
CAPITAL EXPENDITURES – LESS THAN 500 MW

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.

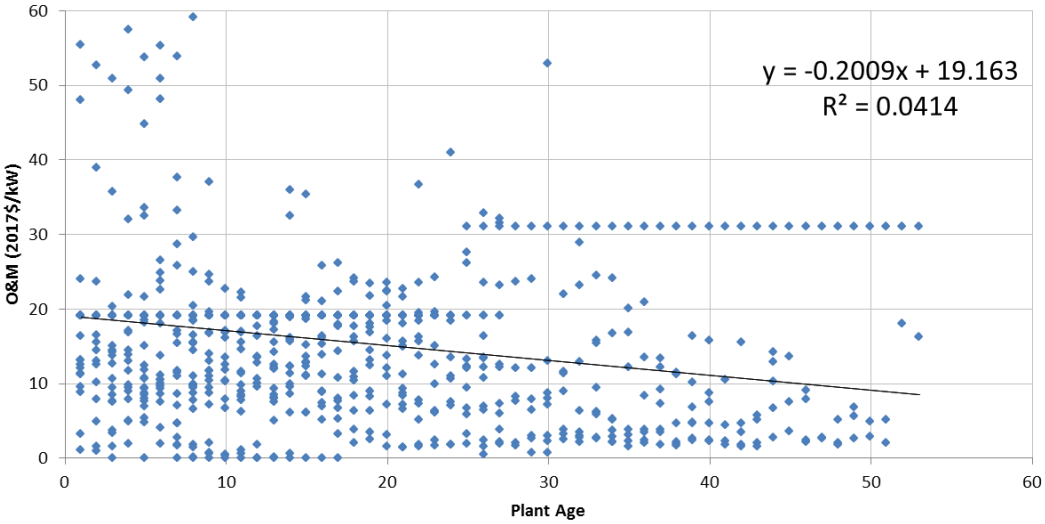
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

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.

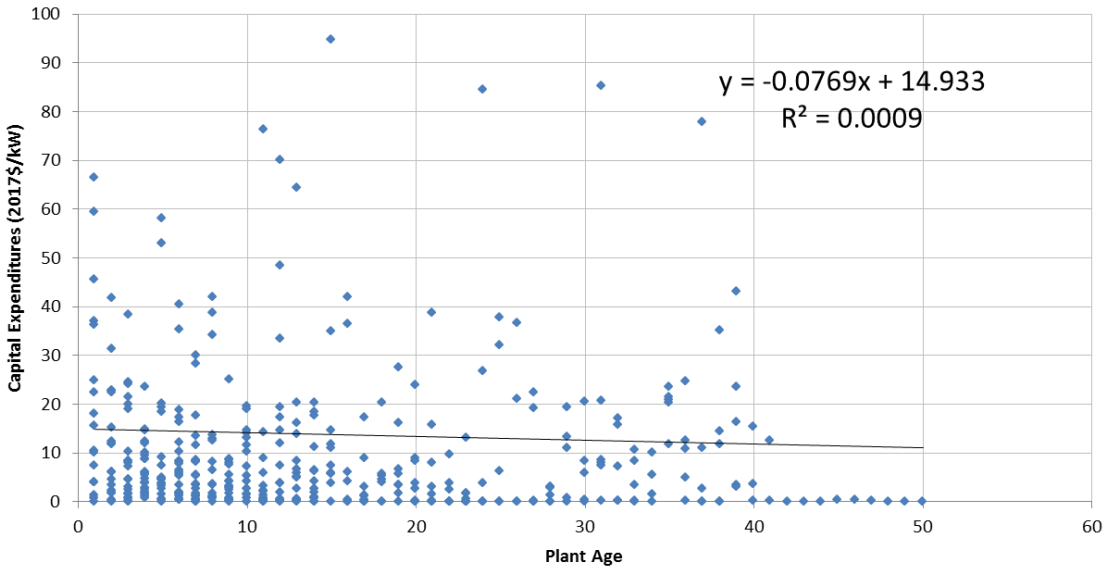
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

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.

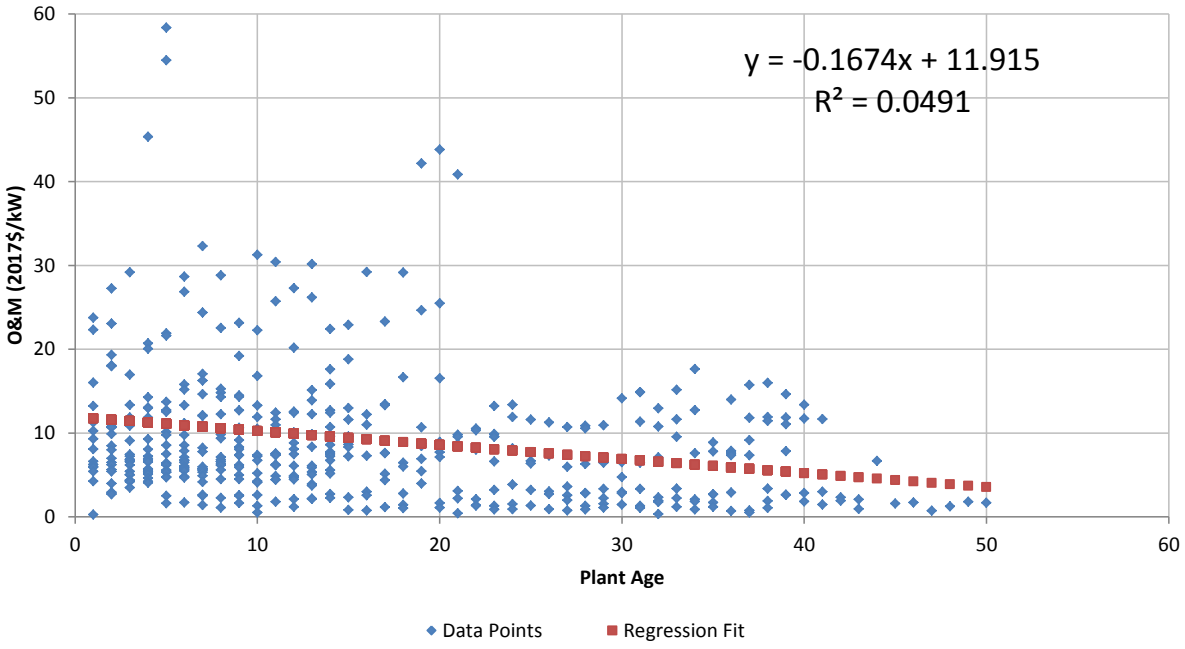
OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

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.

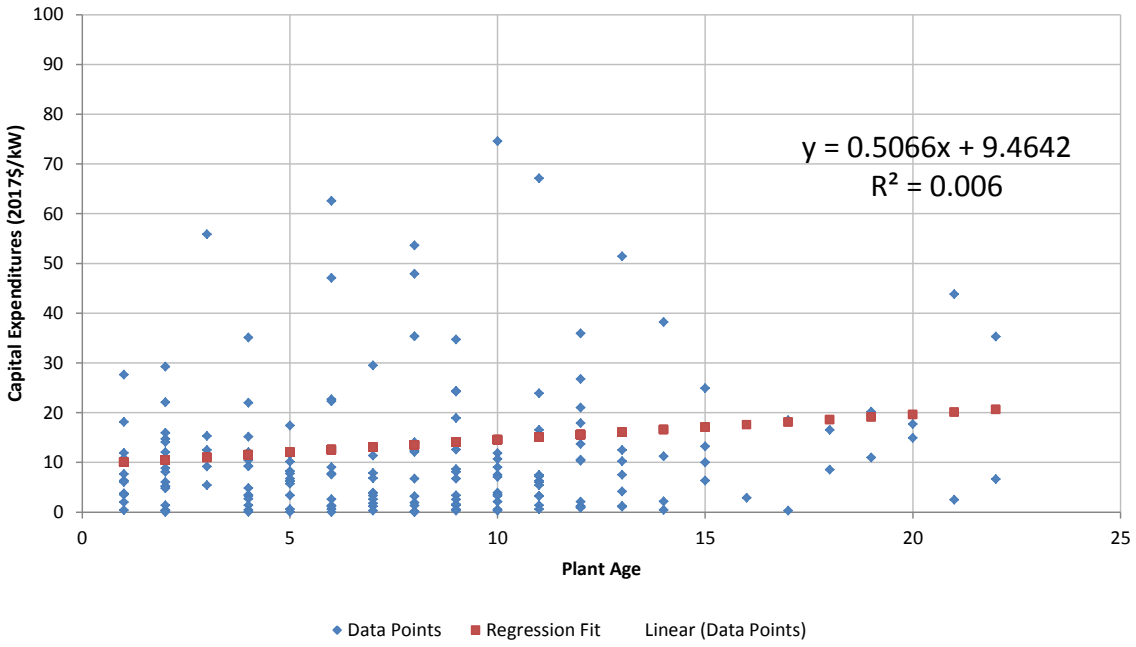
CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

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.

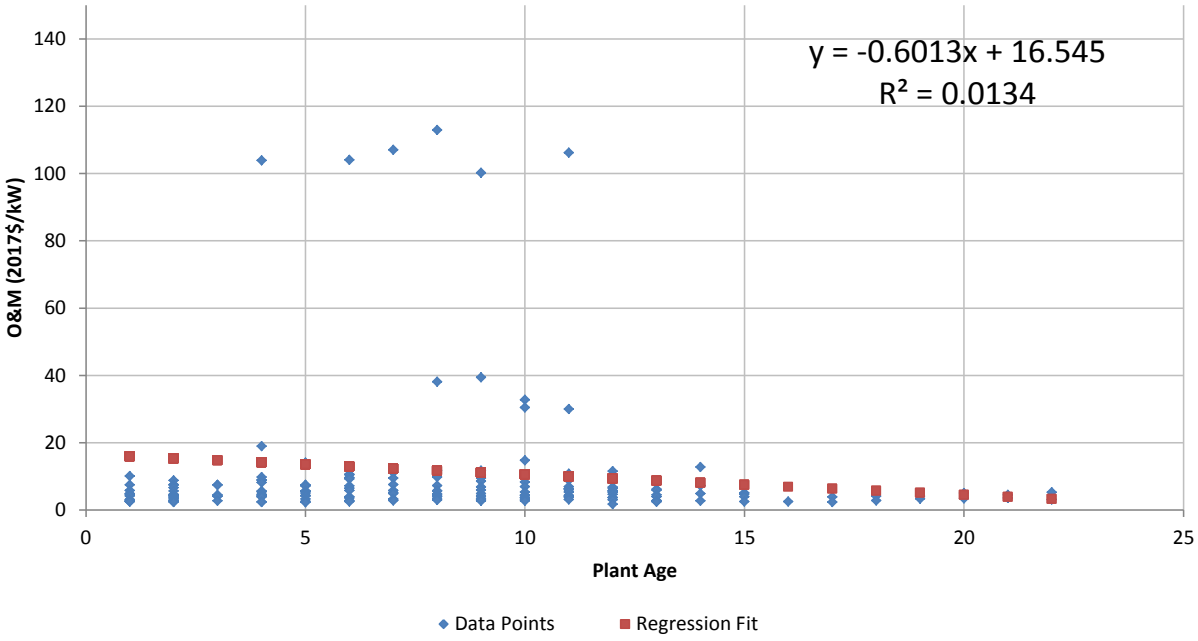
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

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.

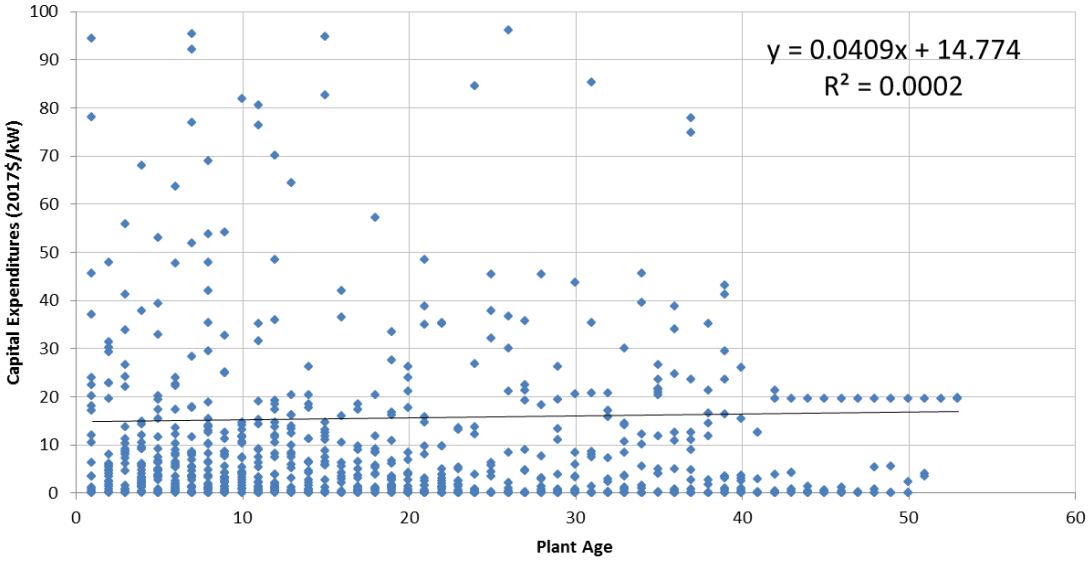
CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

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.

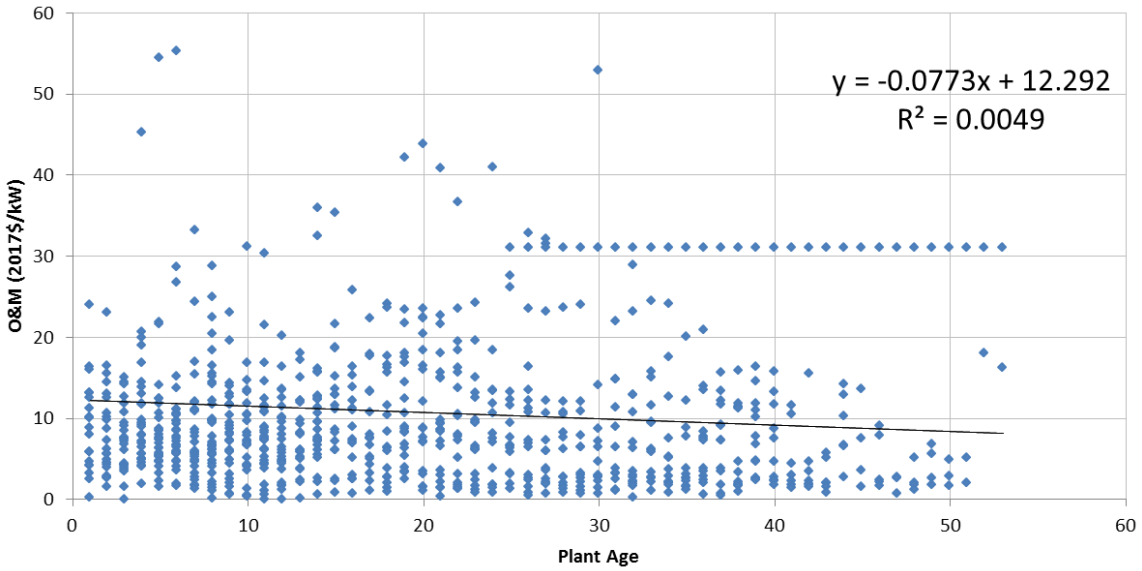
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

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.

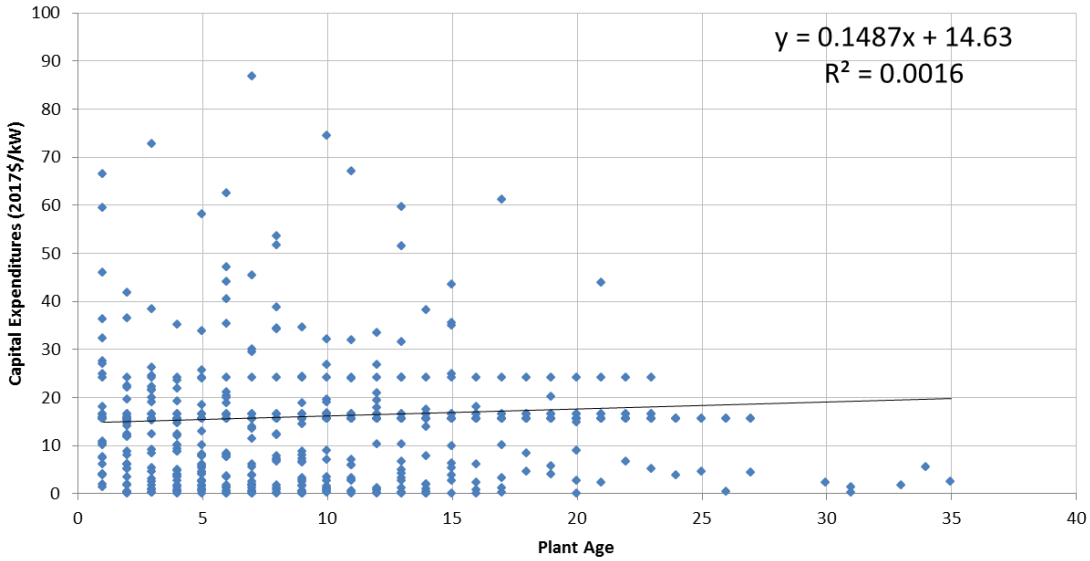
CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

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.

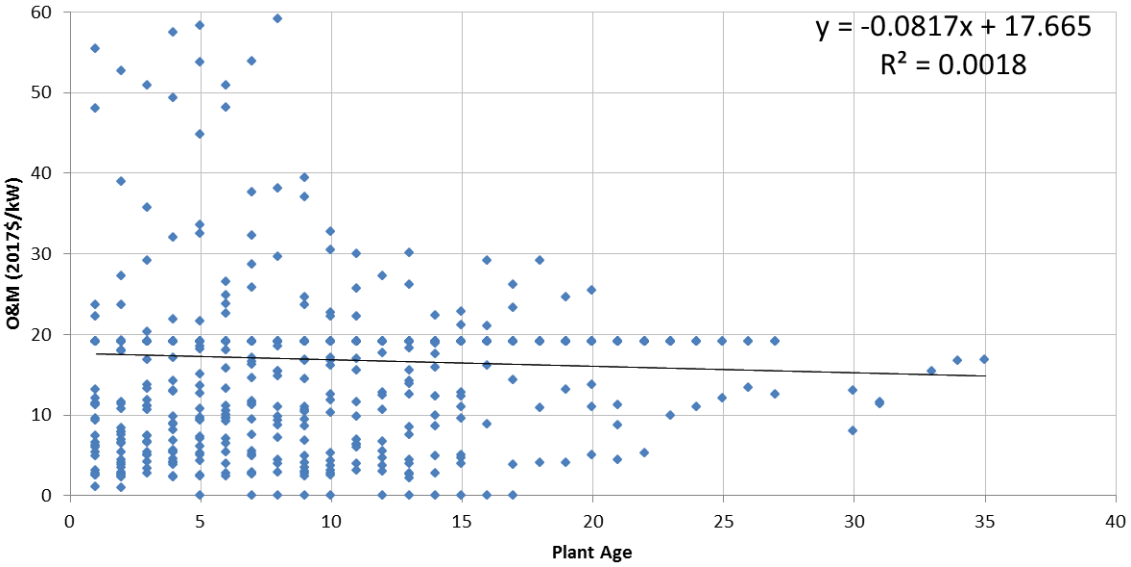
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

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

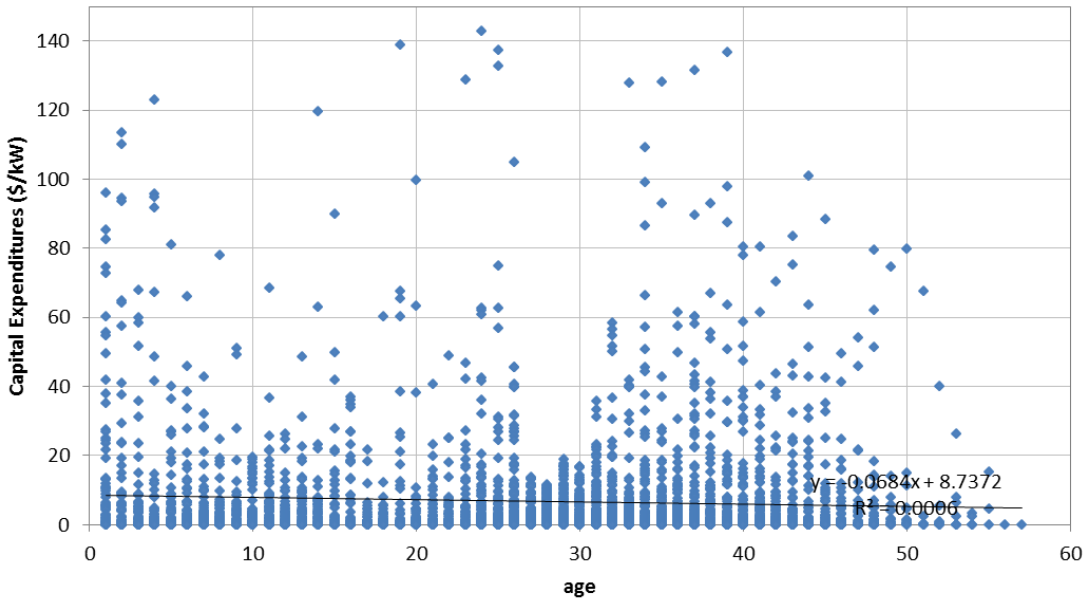
CAPITAL EXPENDITURES – ALL PLANT SIZES

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.

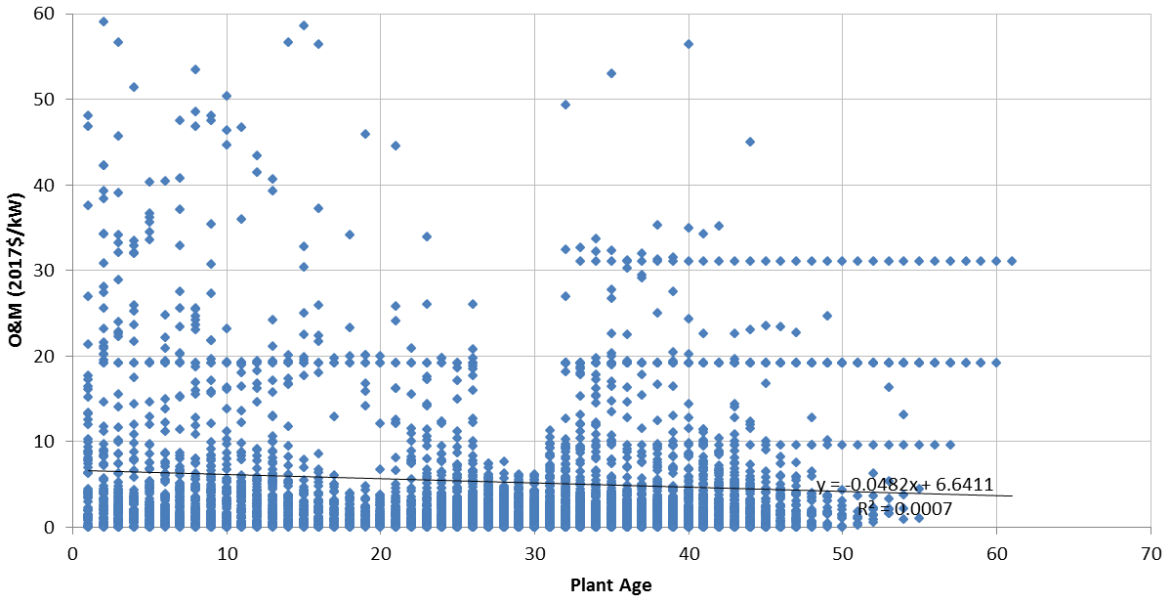
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

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

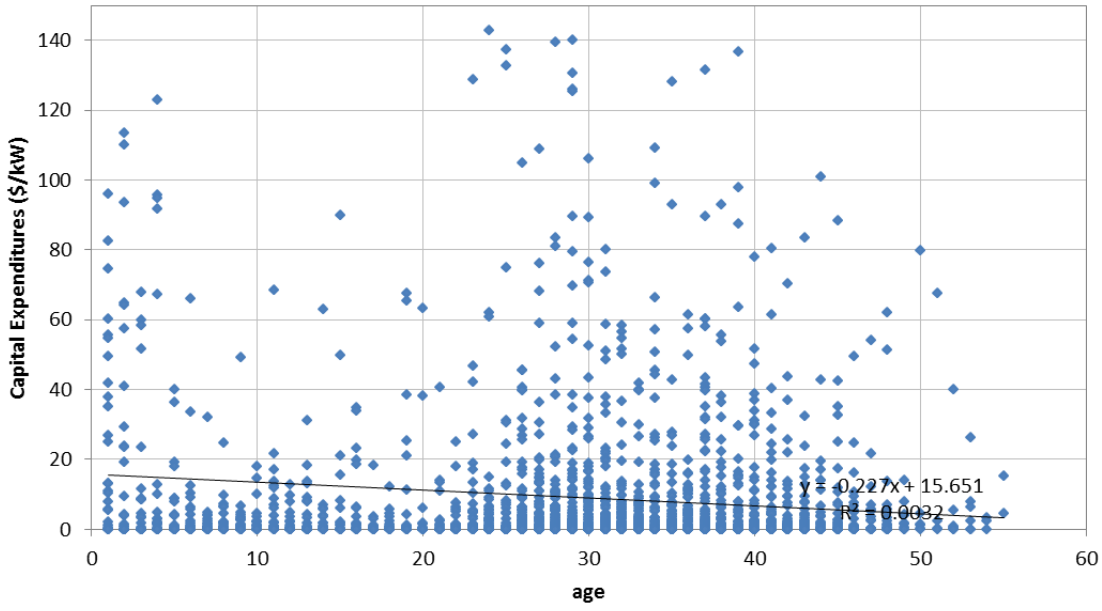
The results of the regression analysis of CAPEX spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.002, which is less than 0.05, age is a statistically significant predictor of CAPEX 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



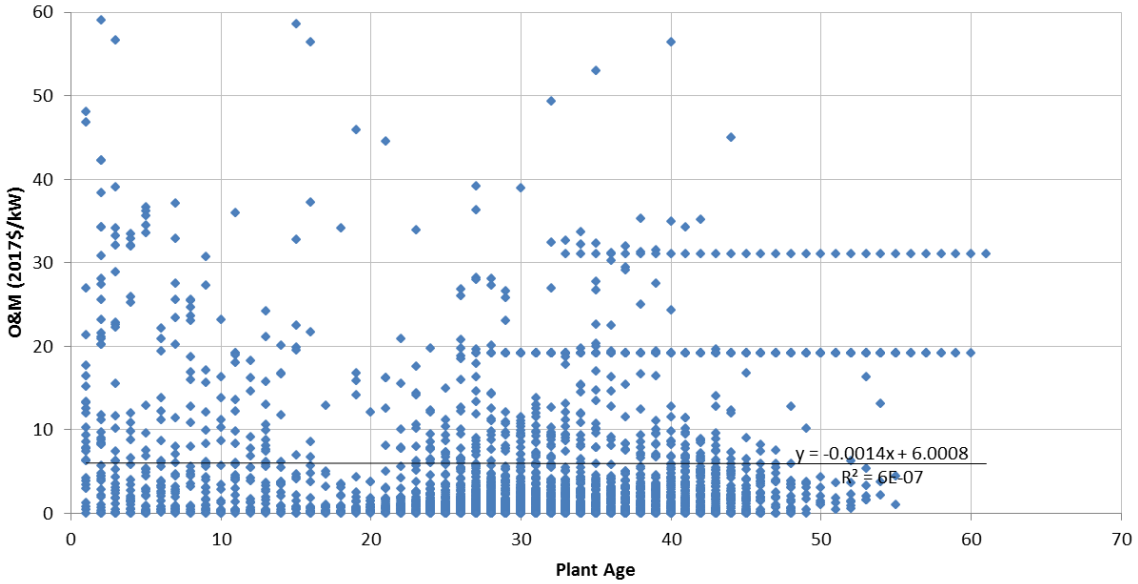
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 100 MW

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.

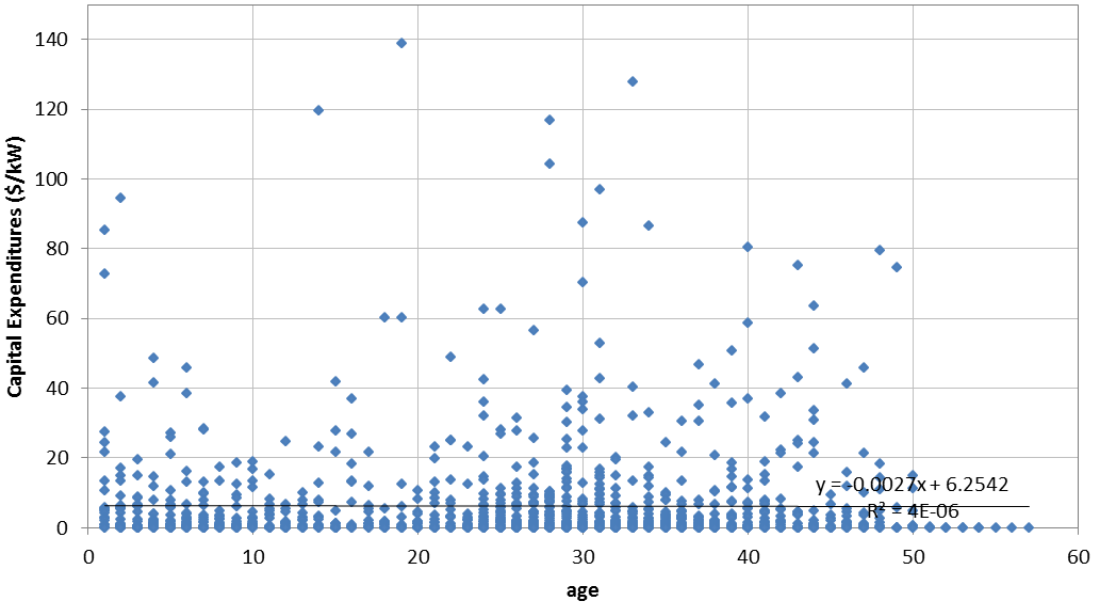
CAPITAL EXPENDITURES – BETWEEN 100 MW AND 300 MW

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

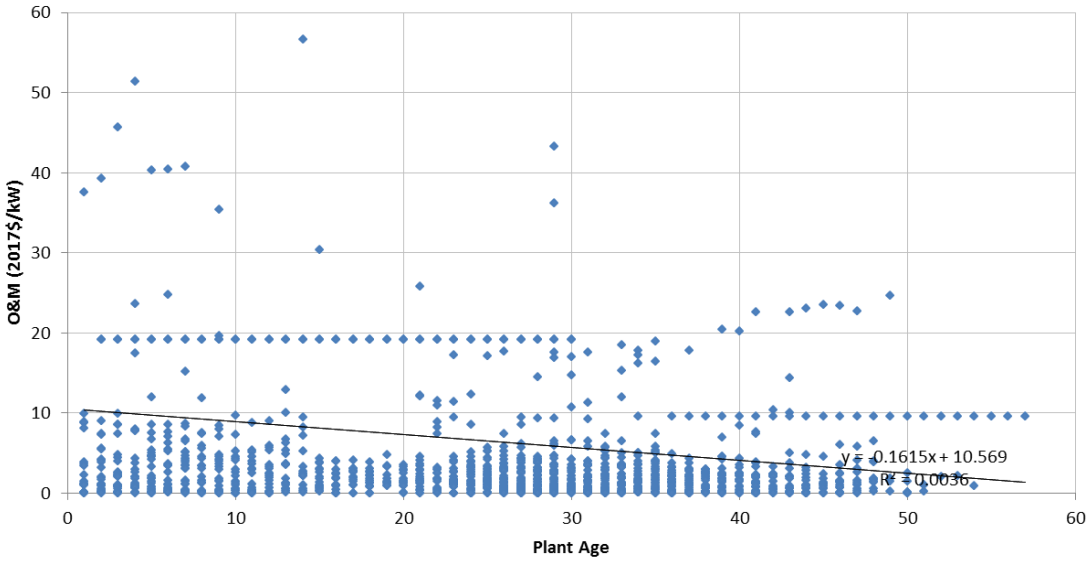
The results of the regression analysis of O&M spending for gas/oil CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.023, which is less than 0.05, age is a statistically significant predictor 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

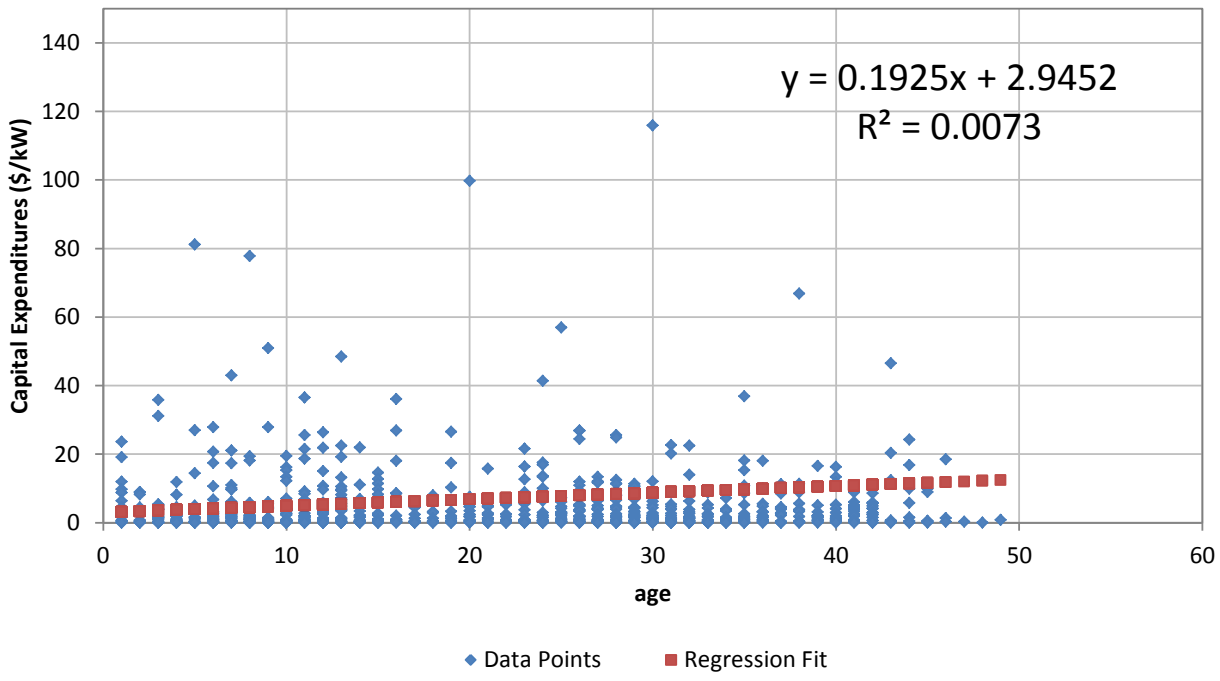
The results of the regression analysis of CAPEX spending for gas/oil CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.010, which is less than 0.05, age is a statistically significant predictor of 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

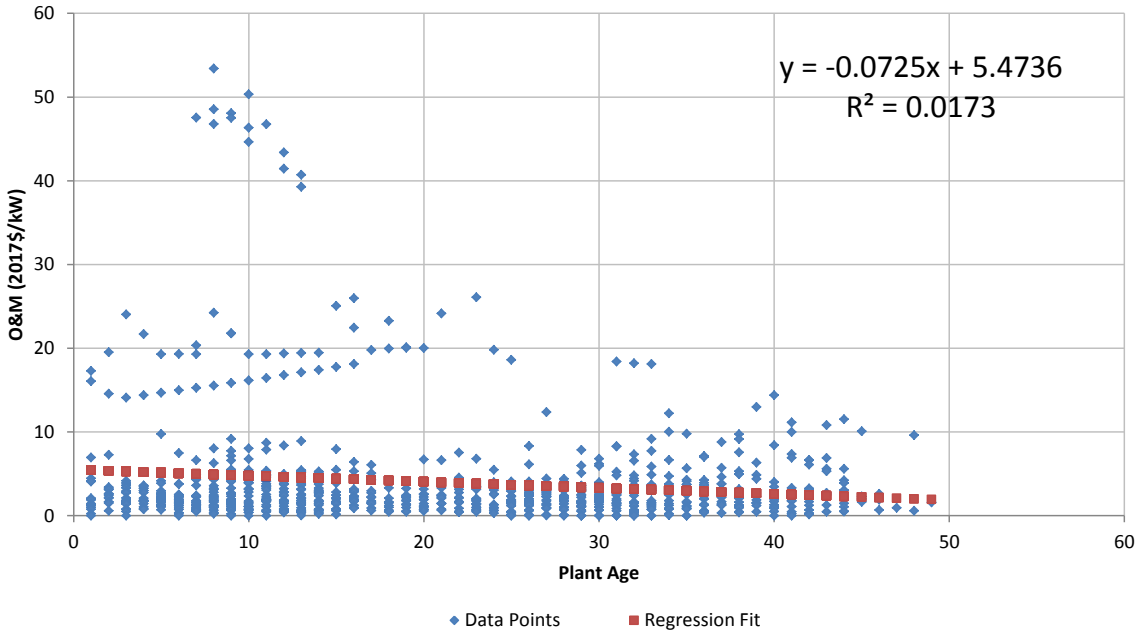
The results of the regression analysis of O&M spending for CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (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

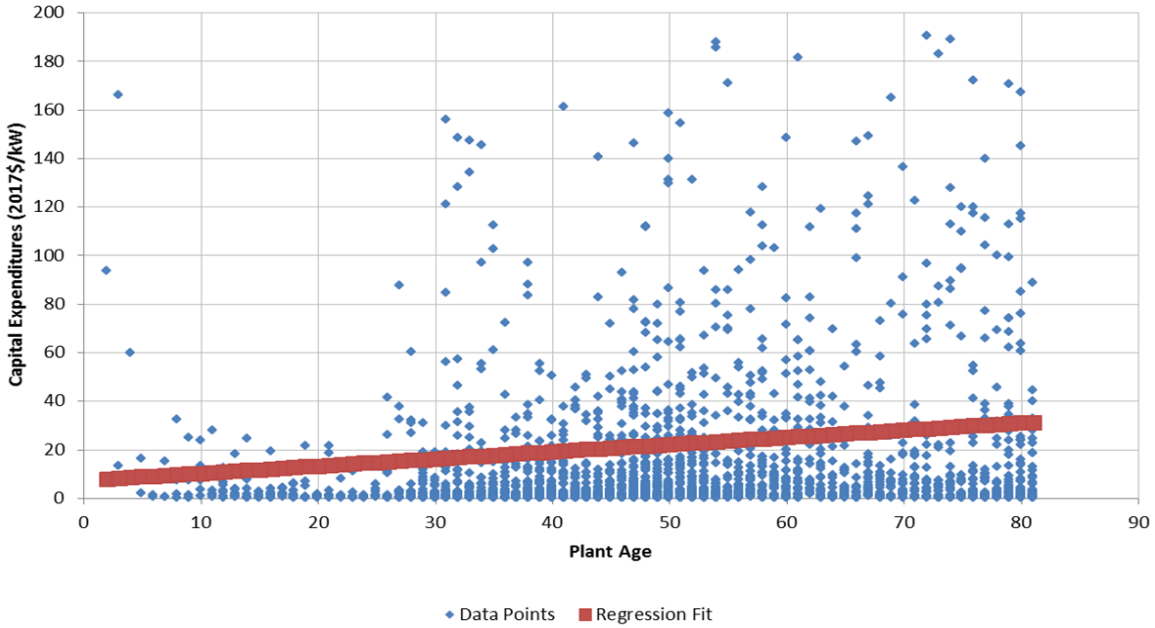
The results of the linear regression analysis of CAPEX spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically 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

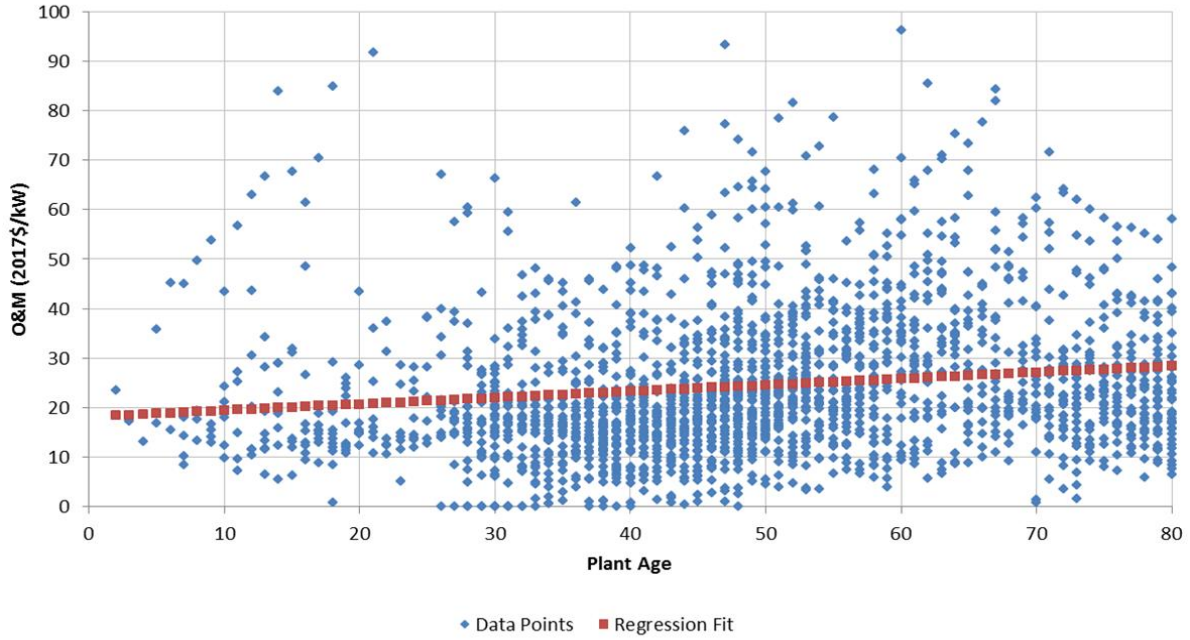
The results of the linear regression analysis of O&M spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically 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

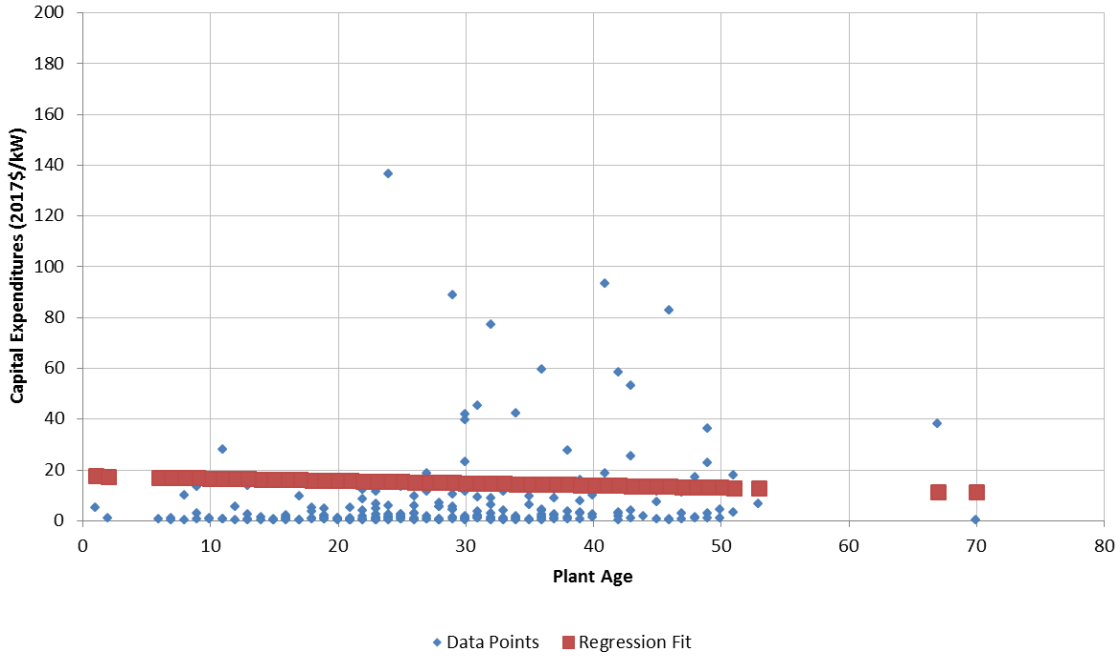
CAPITAL EXPENDITURES – ALL PLANT SIZES

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.

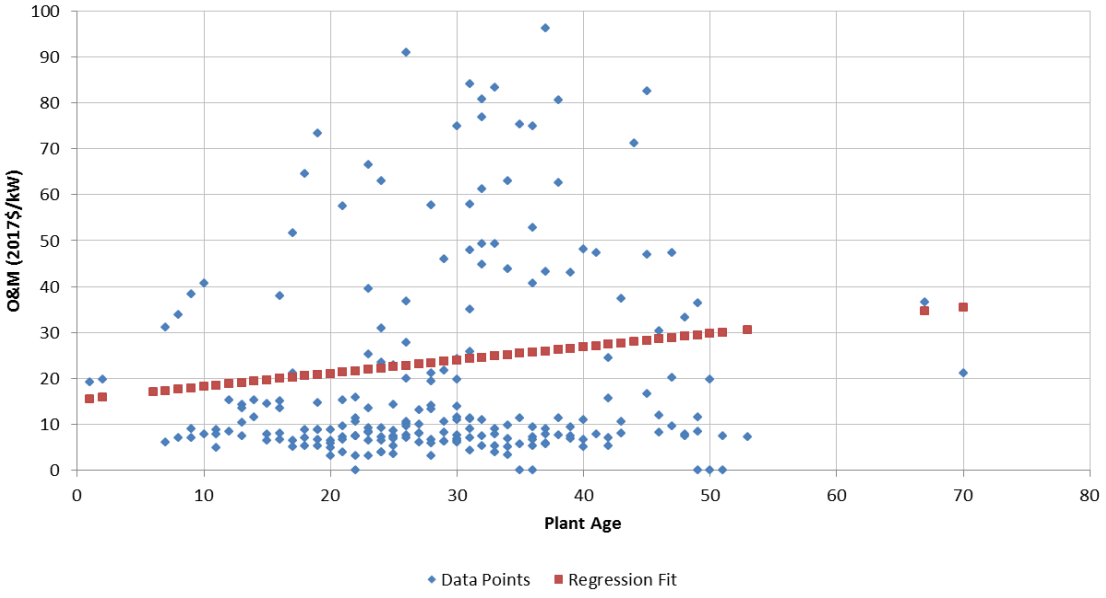
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

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.

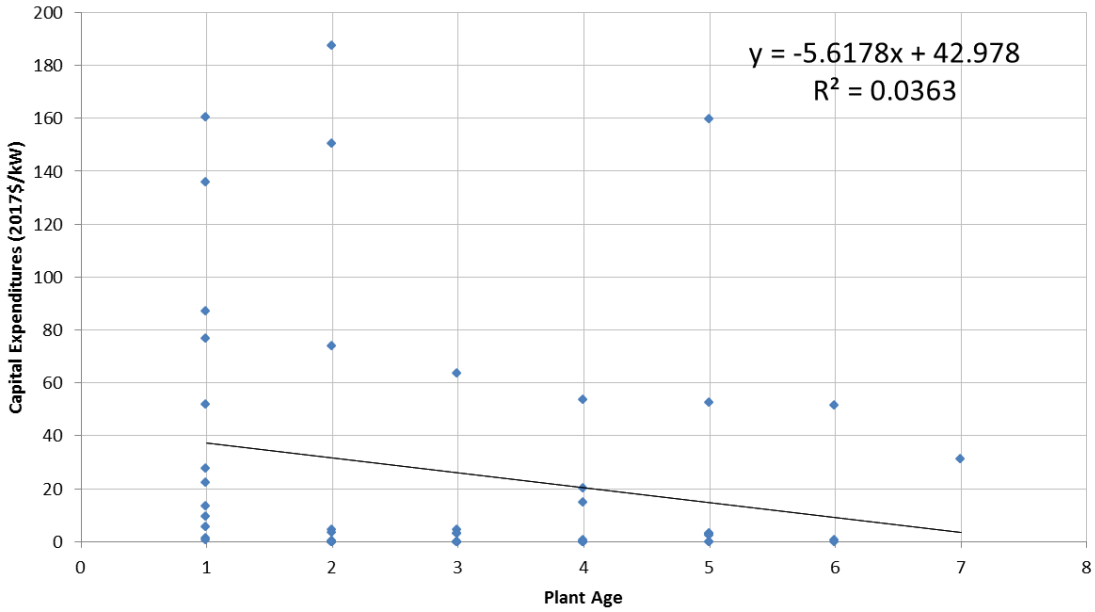
Thus, Sargent & Lundy had to rely on a limited dataset for solar PV consisting of 15 sites. The average change in TCP for these sites was approximately $26/kW-year. Based on the available FERC Form 1 information, it cannot be determined whether this change in TCP was due to typical CAPEX for solar PV, 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)

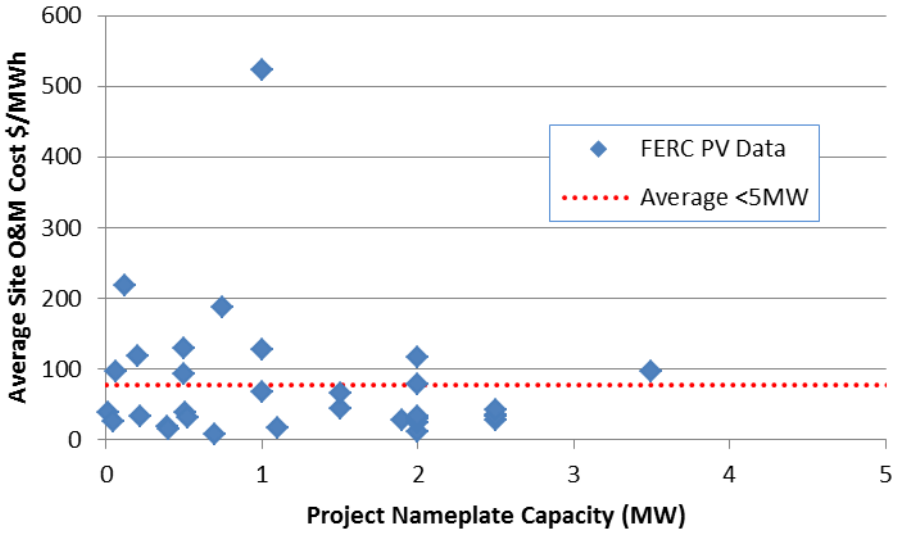


Figure G-3 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (> 5 MW)

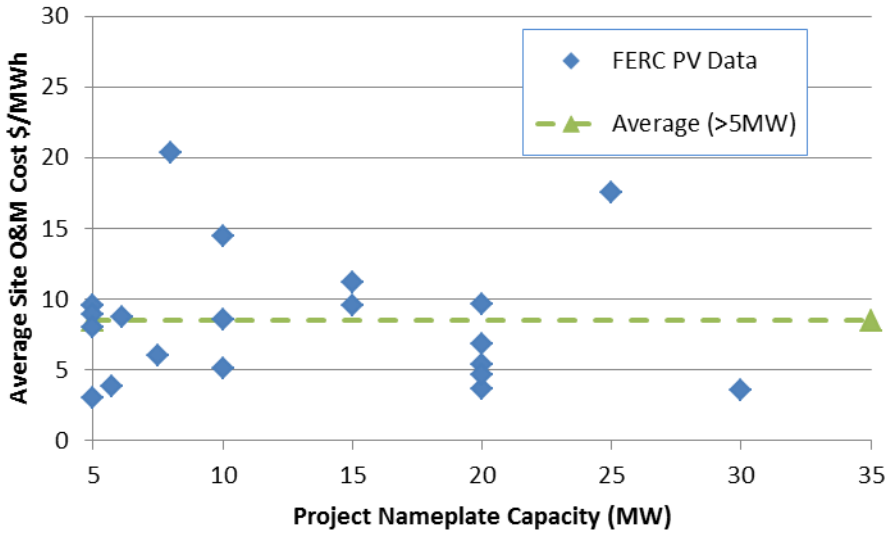


Figure G-4 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (< 5 MW)

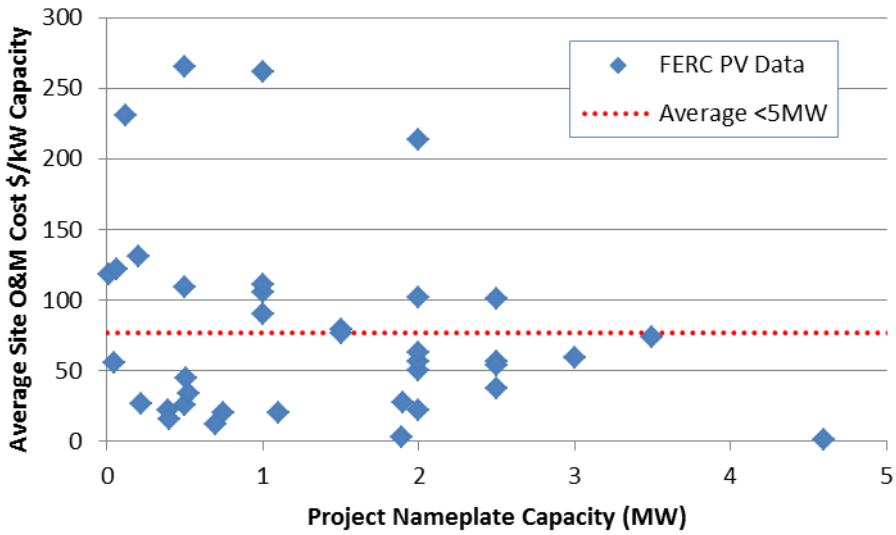
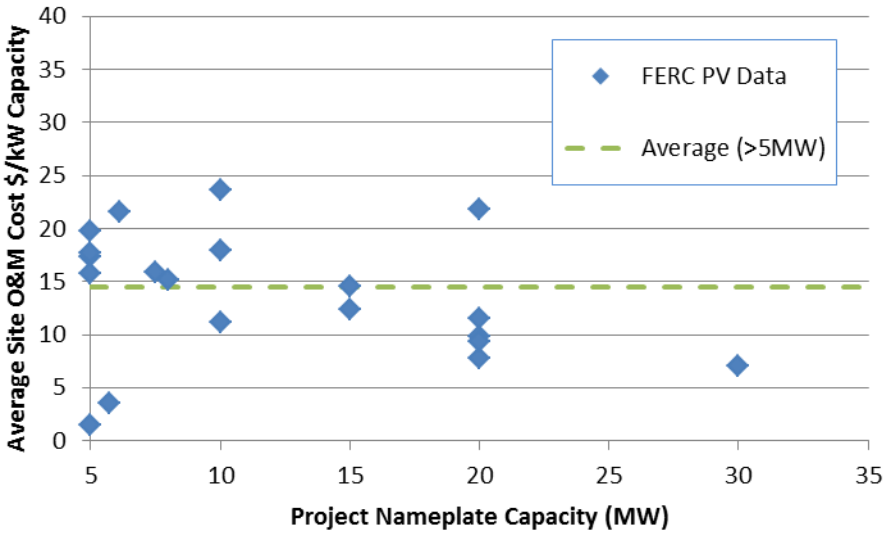


Figure G-5 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (> 5 MW)



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

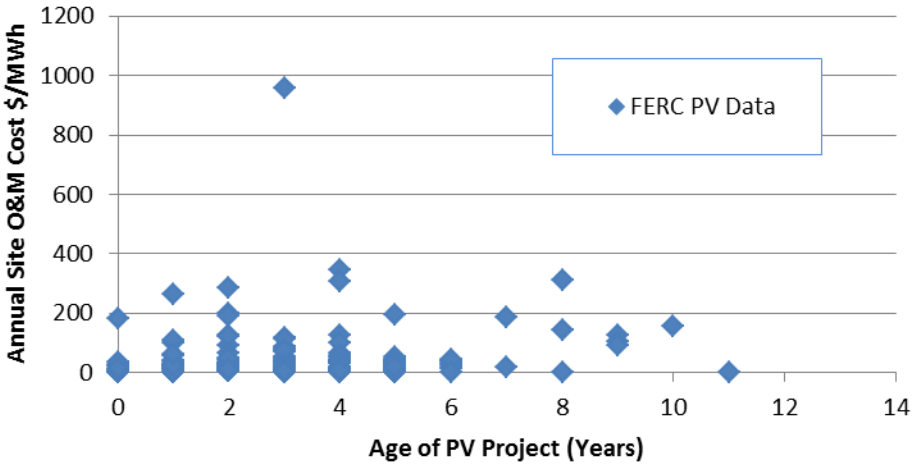
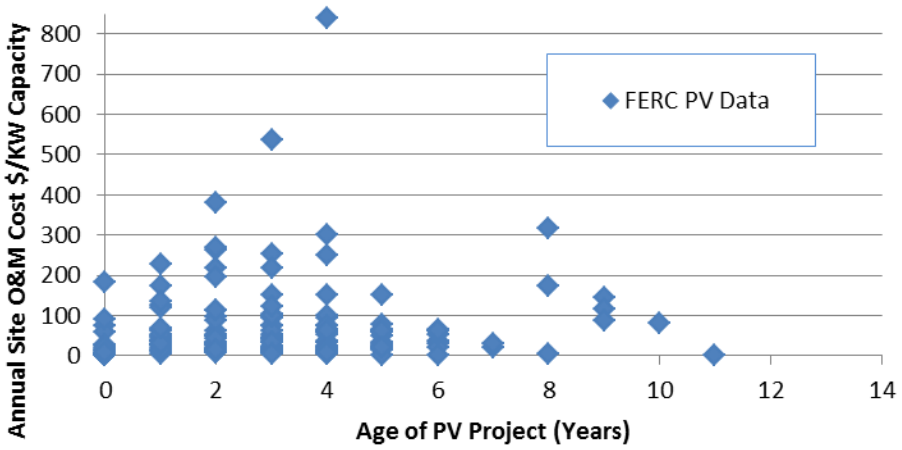


Figure G-7 — Annual Site O&M Cost per kW-Year Capacity vs. Age of Project



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

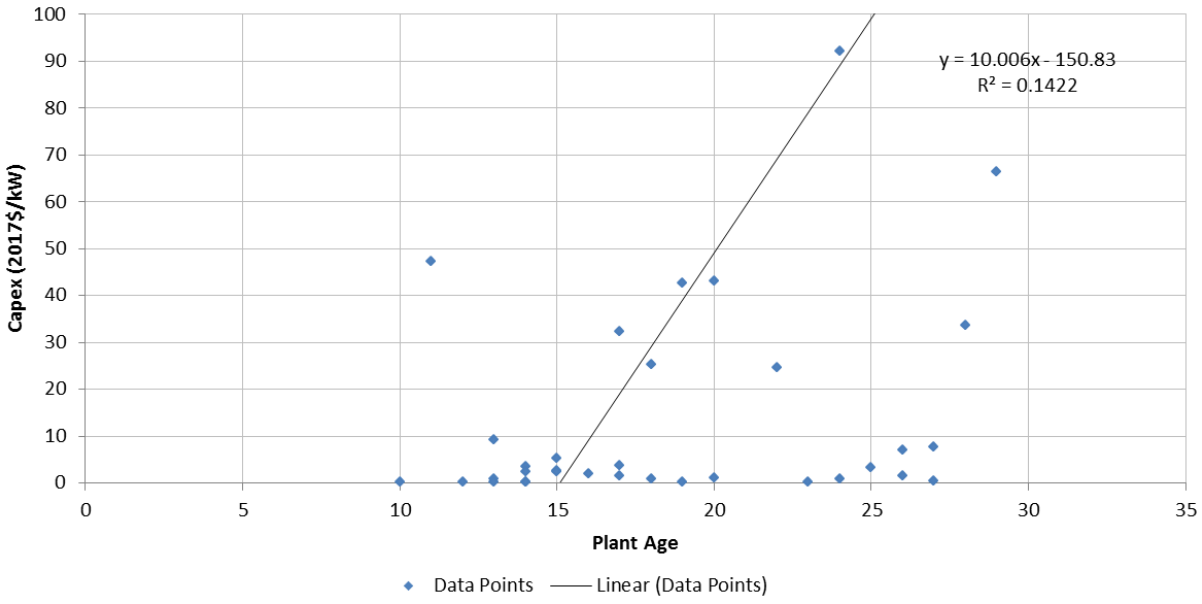
CAPITAL EXPENDITURES

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



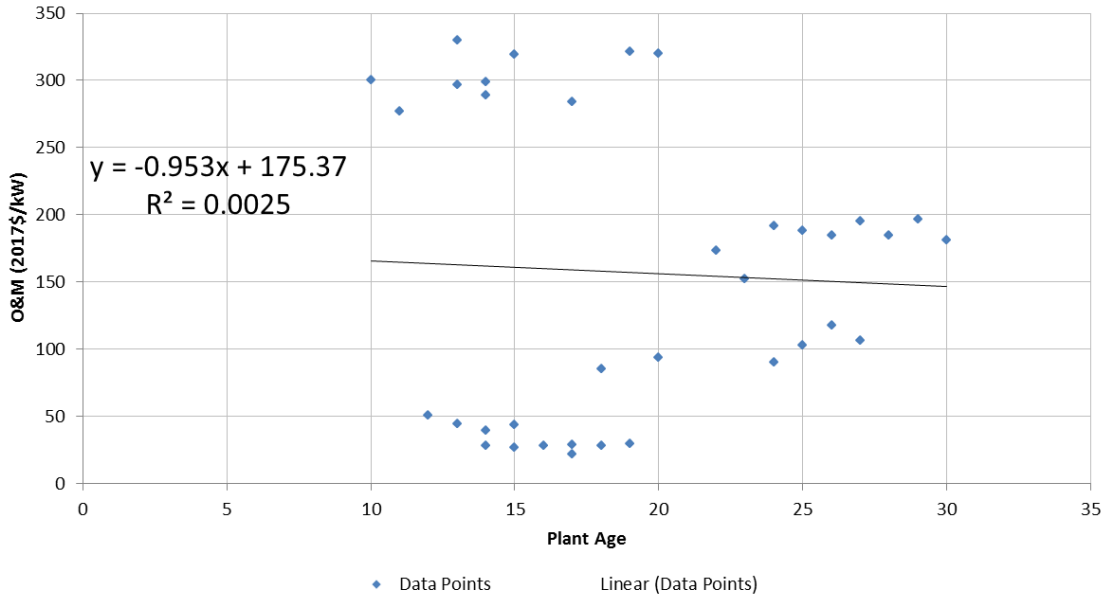
OPERATIONS & MAINTENANCE EXPENDITURES

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

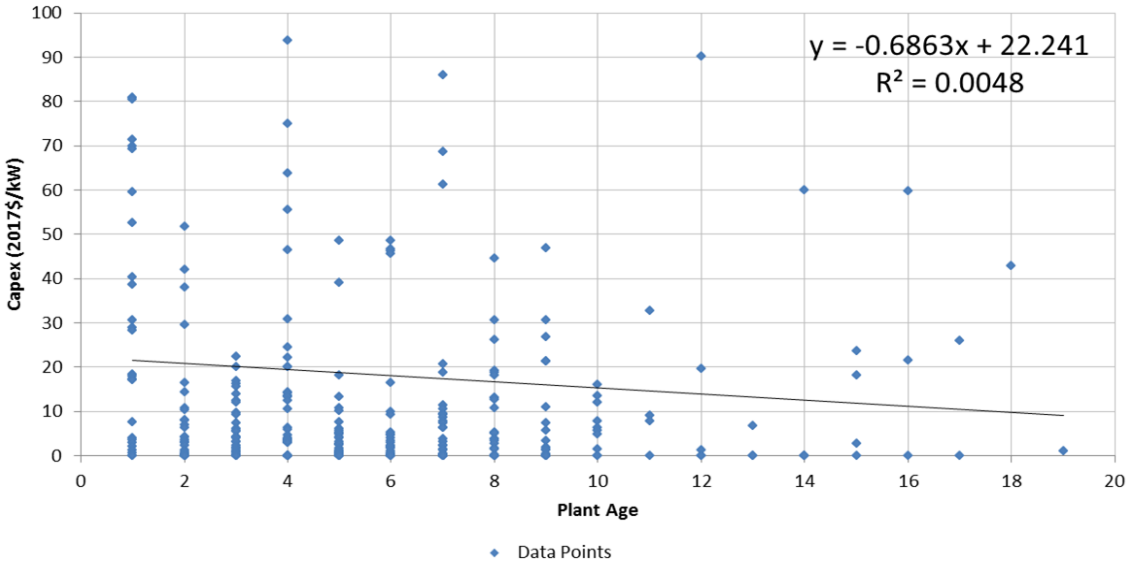
Full Dataset

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.

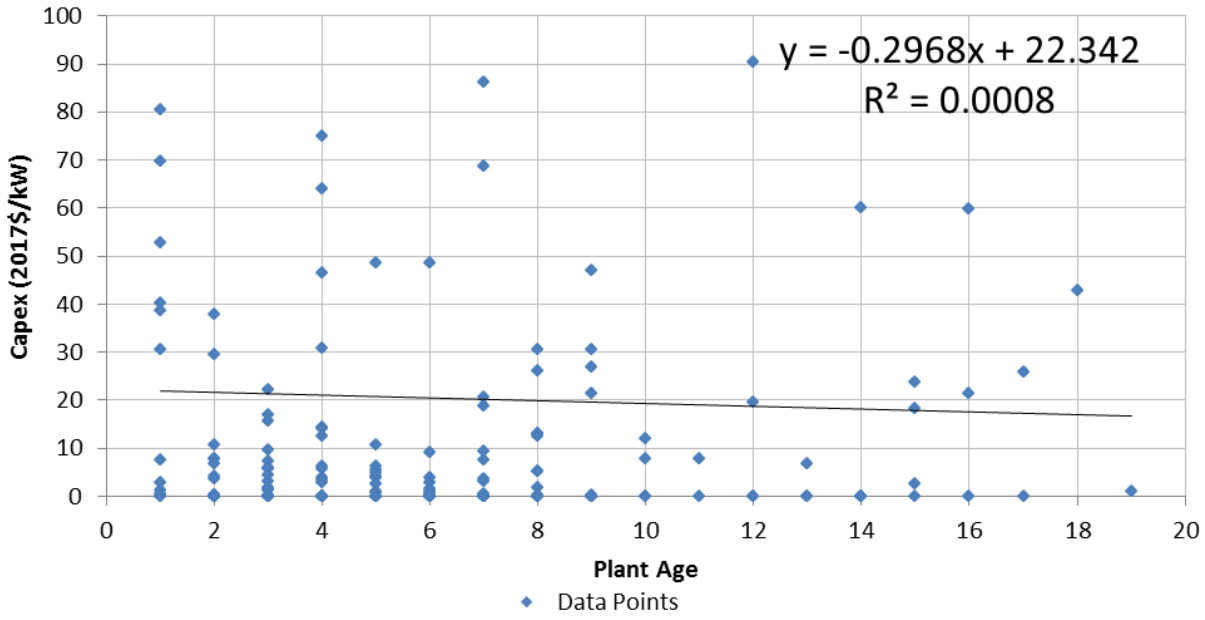
0-100 MW

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.

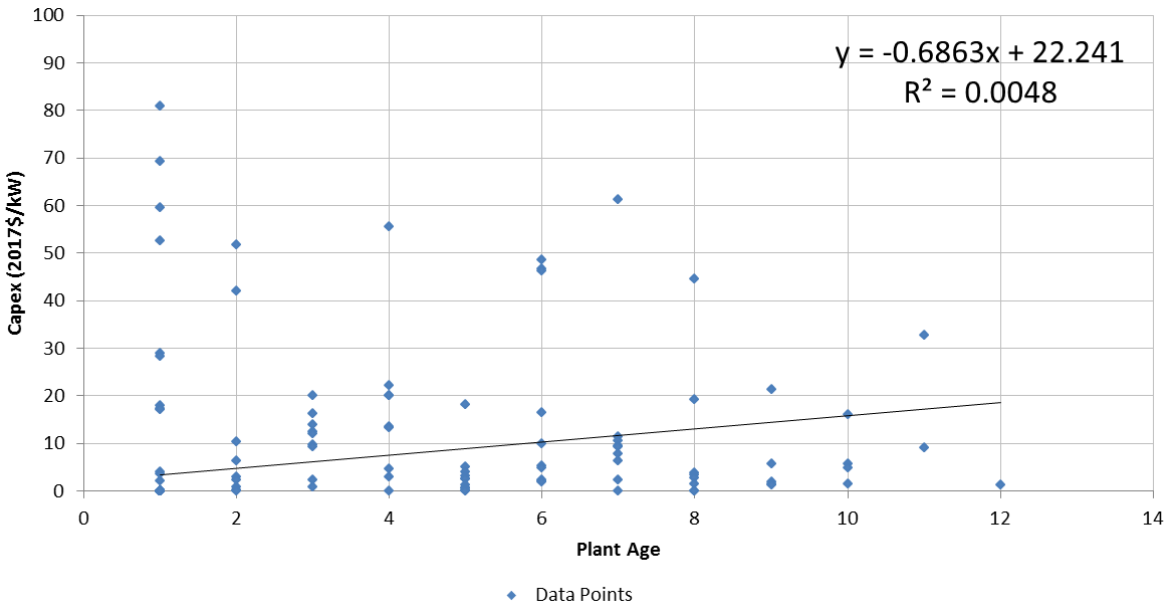
100-200 MW

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.

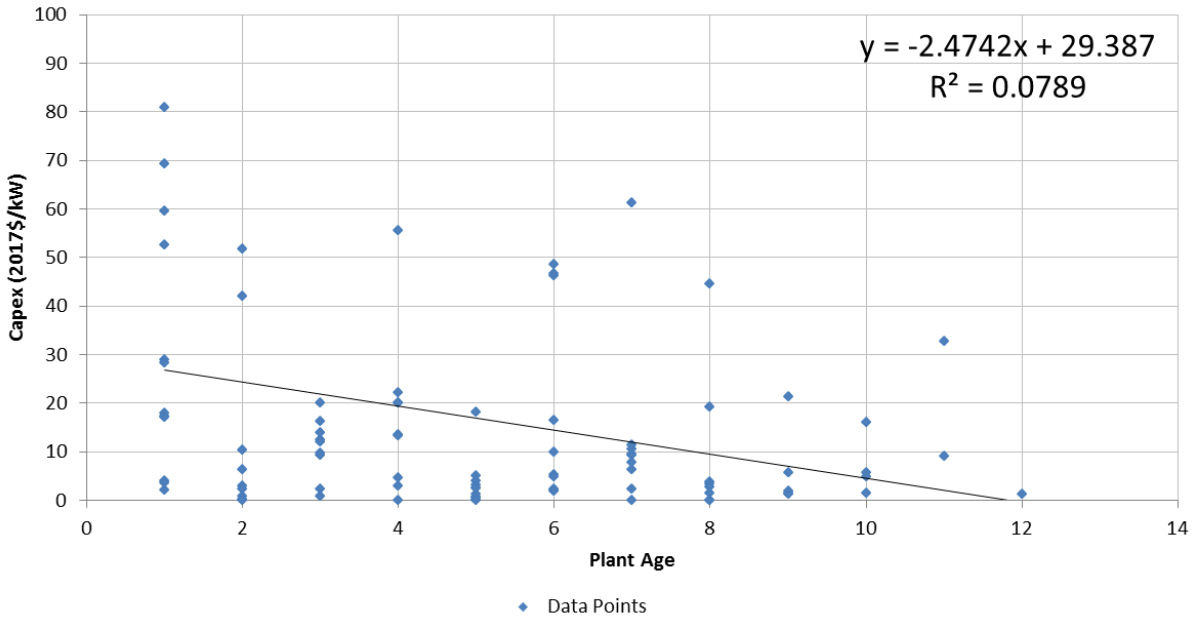
Greater than 200 MW

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

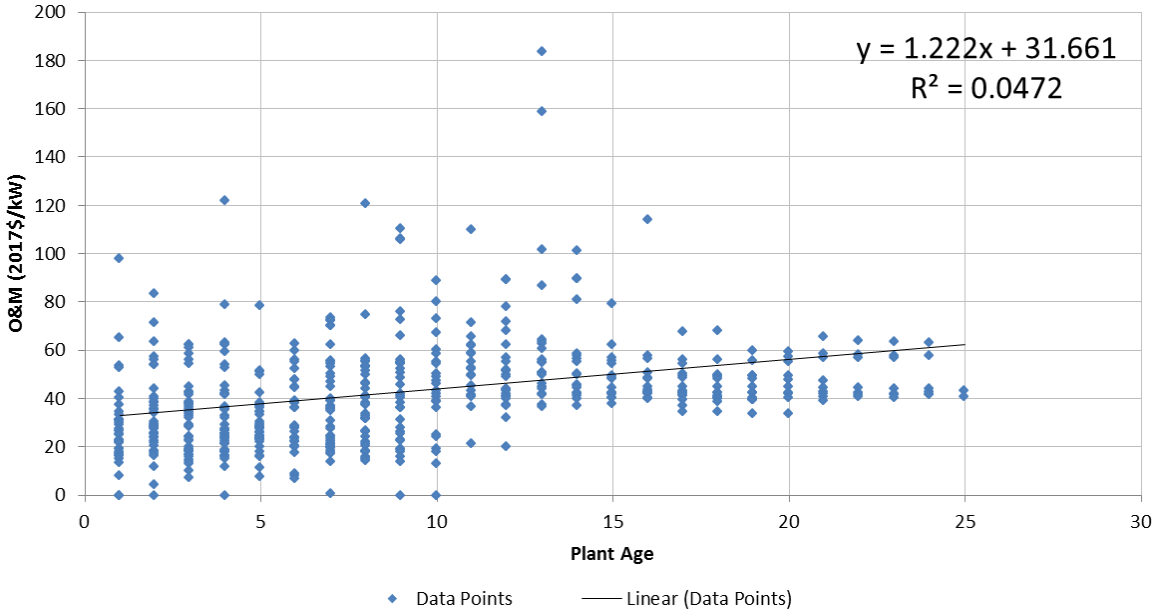
The results of the linear regression analysis of O&M spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M 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

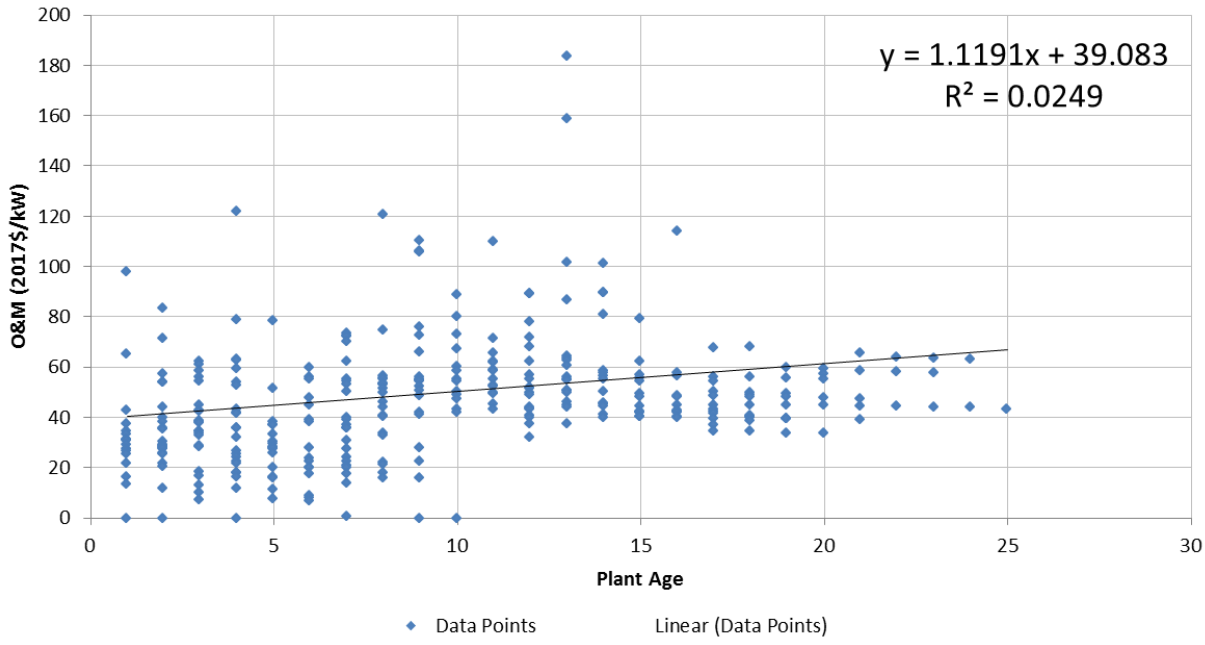
The results of the linear regression analysis of O&M spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.003, which is less than 0.05, the dataset age is a statistically significant predictor 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

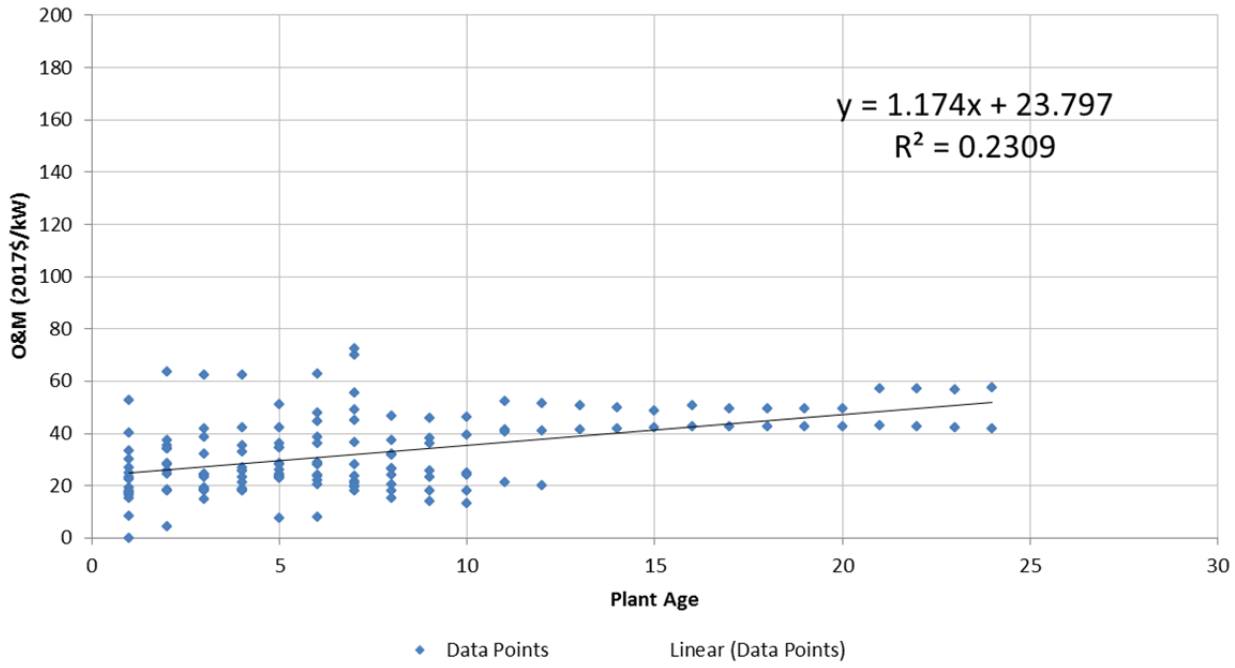
The results of the linear regression analysis of O&M spending for wind plants between 100 MW and 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (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

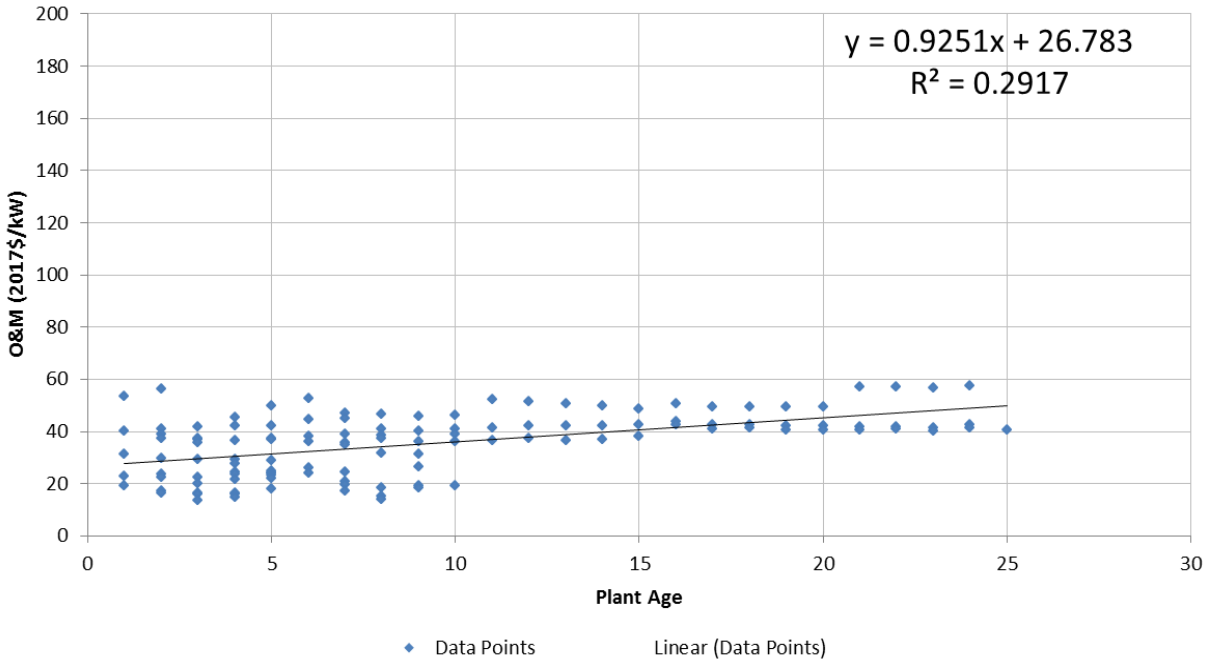
The results of the linear regression analysis of O&M spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (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 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

Exhibit 2-163
Trump Advisor Says Electricity Customers Pay for 202(c) Orders

Upgrade your Chrome brows...
Get localized weather, trending news, AI p...
Close
Add it now

HELOC
Never Borrow From The Bank. If You Own a Home, Borrow From Yourself!
Lendgo.com NMLS1693075
Select Loan Amount
$50,000
15-Year Term
Monthly Payment
$315/mo
6.49% APR
Get Cash Now →
Sponsored

Story by Laura Sanicola • 1w • 3 min read

IN THIS ARTICLE

DUK ▲ +1.15% CMS ▲ +1.17% SO ▲ +0.71%



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.


13 Retirement Blunders to Avoid
Fisher Investments · Sp

"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.

Denver 39°F

Search the web



Progressive Insurance · Spc

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.



Ask a Pro: "Best RMD Tax...

SmartAsset · Sponsored

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

Sponsored Content



Fisher Investments

How Long Does $1 Million Last After 60?

Sponsored



Prosper Daily

Elon's Next Move Could Mint Millionaires

Sponsored

More for You

Seeking Alpha · 1w

Trump outlines plan for tech giants to fund new power plants, shift costs to data centers

134 3



POLITICO · 1w

Trump suffers major losses in his war on offshore wind

2k 264



CNN · 1w

Trump is threaten attack a country t produces three ti

2k 1k

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	)

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

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

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

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

Mailed Date: January 23, 2024
Adopted Date: December 6, 13, 20, 2023

TABLE OF CONTENTS

I. BY THE COMMISSION 3
A. Statement 3
B. Discussion 7
1. Electric Resource Planning 7
2. Clean Energy Plans Pursuant to SB 19-236 9
3. Procedural Background 13
C. Phase I Decision and Public Service CEP 18
D. Phase II Filings 19
1. 120-Day Report 19
2. CDPHE Verification 21
3. IE Report 22
4. Intervenor Comments 22
5. Comments from the Northern Cheyenne Nation 24
6. Public Comments 24
7. Public Service's Response Comments and the UPP 25
E. Modification of the CEP's Resource Portfolio 27

Colorado PUC E-Filings System

1. Emission Reductions 34
2. Reasonable Cost to Customers 38
3. Reliability and resilience of the electric system 45
4. Future Technology Development 50
5. Transmission Concerns 54
6. Conclusion 57
F. Transmission 58
1. Phase II Changes in Transmission Investments 58
2. Party Comments 60
3. Findings and Conclusions regarding Transmission 63
G. Performance Incentive Mechanisms 69
1. Background and Party Comments 69
2. Findings and Conclusions 72
H. The Sand Creek Massacre National Historic Site and Bid 1029 80
I. Hayden Biomass 83
1. Party Comments 84
2. Findings and Conclusions 87
J. Backup Bids 90
1. Party Comments 90
2. Findings and Conclusions 93
K. Section 123 Resources 95
L. Prospective New Load 97
M. Clean Energy Plan Rider (CEPR) 99
1. Public Service's New CEPR Proposals and Party Comments 100
2. Findings and Conclusions 102
N. Best Value Employment Metrics 103
O. In Service Date Extensions 107
P. Repricing 108
Q. 2024 Just Transition Solicitation 109
1. Modeling Improvements 109
2. Non-Negotiable PPA Terms 113
3. Company Ownership 115
4. Just Transition Bids 116
5. Discount Rates 118

6. Comprehensive Rate Analysis 118
R. Miscellaneous Issues for Future Proceedings 119
1. Equity Directives 119
2. CPCN Prioritization 121
3. Voluntary Additional Emissions Reduction Program 123
S. Requests not Explicitly Addressed 125
II. ORDER 125
A. The Commission Orders That: 125
B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS December 6, 13, and 20, 2023. 127

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]

[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

[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.

[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.

[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]

[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]

[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.

[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

[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

[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).

[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

[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

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	)

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

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 3
A. Statement 3
B. Procedural History 4
C. Background of the CEP Delivery Motion 10
D. Component 1, Stage 1 12
1. Party Positions 12
2. Findings and Conclusions 18
a. PPA Projects 18
b. Utility-Owned Projects 20
E. Component 1, Stage 2 24
1. Party Positions 24
2. Findings and Conclusions 29
F. Other Component 1 Issues 33
1. Selection of Additional Solar and Solar Plus Storage Bids 33
2. Presumption of Prudence for Incremental Cost Increases 34
G. PPA Execution and Requests for Rule Variances 35
1. Party Positions 35
2. Findings and Conclusions 37

Colorado PUC E-Filings System

H. JTS Proceeding 39
1. Party Positions 39
2. Findings and Conclusions 41
I. Replacement for Bid 0235 42
1. Party Positions 42
2. Findings and Conclusions 47
J. Thermal Resource Price Increases 51
1. Party Positions 51
2. Findings and Conclusions 54
K. Bid 0989 56
1. Party Positions 56
2. Findings and Conclusions 57
L. Bid 0011 59
1. Party Positions 59
2. Findings and Conclusions 62
M. Purchase of Plains End 63
1. Party Positions 63
2. Findings and Conclusions 65
N. Alternative Thermal Proposals 66
1. Party Positions 66
2. Findings and Conclusions 67
O. Expansion of ISOC Incentives 67
1. Party Positions 67
2. Findings and Conclusions 69
II. ORDER 70
A. The Commission Orders That: 70
B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING December 16, 2024, and December 20, 2024. 71

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.

[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]

[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]

[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	)
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

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

tristate.coop/tri-state-makes-craig-generating-station-unit-1-available-operate-compliance-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.

A Touchstone Energy® Cooperative 

©2026 Tri-State Generation and Transmission Association, Inc. Power supplier to the rural west.

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	)

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

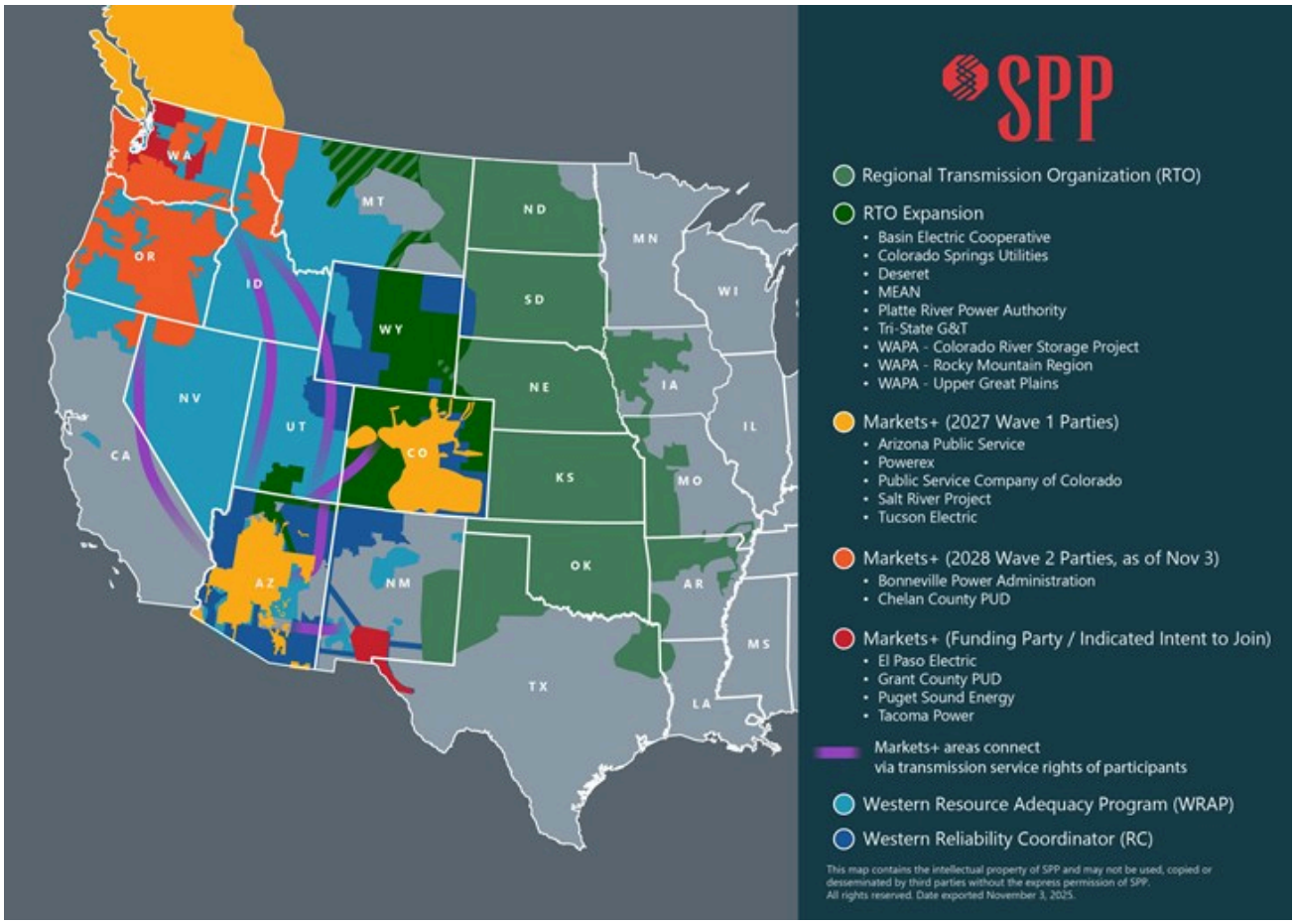
Exhibit 2-167
SPP Markets+ Website

Markets+ - Southwest Power Pool

www.spp.org/marketsplus

MARKETS+

Markets+



Markets+ is more than just a day-ahead market offering. It's a bundle of services that will centralize day-ahead and real-time unit commitment and dispatch and pave the way for the reliable integration of a rapidly growing fleet of renewable generation.

Working together, we've developed a market design that goes beyond current imbalance market service offerings, enhances reliability, increases participant value, equitably compensates participants and incorporates their diverse perspectives.

The Markets+ program has entered Phase Two – Implementation. Potential participants are encouraged to submit an RMS ticket promptly to begin the registration and onboarding process. Indicating intent to participate by the following key registration deadlines is essential to ensure inclusion in the October 2027 go-live:

- Balancing Authorities: September 1, 2025
- Transmission Service Providers: October 1, 2025
- Market Participants: April 1, 2026

Participants seeking to join after October 2027 are still welcome to submit an RMS ticket to express their interest in Markets+.

Markets+ Phase Two Funding Entities:
As of October 27, 2025

- Arizona Public Service
- Bonneville Power Administration
- Chelan County PUD
- Grant County PUD
- Powerex
- Puget Sound Energy
- Salt River Project
- Tacoma Power
- Tri-State G&T
- Tucson Electric Power
- Xcel/Public Service Company of Colorado

For a list of participants, click here.

Quick links:

- **Visit the Markets+ Stakeholder page** for events and materials related to the Markets+ stakeholder groups
- **Markets+ Tariff**

- To receive emails related to Markets+ groups and task forces, subscribe to each group's exploder. For general Markets+ information, subscribe to the SPPMarkets+ Exploder on your **account page. (Learn more about Exploders here.)**
- **Market+ Project Timeline**

Latest Markets+ Phase Two News:

- February 14, 2025 | Markets+ phase two development confirmed with western market commitments
- January 16, 2025 | SPP's Markets+ tariff receives FERC approval
- July 31, 2024 | FERC requests additional information regarding Markets+ tariff filing; SPP coordinating response
- June 5, 2024 | SPP files expanded regional transmission organization tariff to include western entities
- April 15, 2024 | Western utilities express support for continued Markets+ development
- April 1, 2024 | Southwest Power Pool completes and files Markets+ tariff with collaboration and support from western stakeholders

WESTERN SERVICES

- › Western Newsroom
  - Press Releases
  - COVID-19
  - 2021 Winter Storm Review
  - Holistic Integrated Tariff Team
  - Stakeholder Report
- Western Events
  - Calendar
  - Registration
- › Markets+
  - Markets+ Initiative Requests
  - Join Markets+
- › RTO Expansion
  - New Member Integration
  - RTO Expansion Program Documents
  - Southwest Power Pool Current List - RTO Expansion Project 20240412
  - RTO Expansion Revision Requests
- Western Resource Adequacy Program
- › Western RC Services
  - WIT Administration
  - Modification Oversight Process

- Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP)
- › WEIS
    - WEIS Revision Requests

RELATED DOCUMENTS

- Help Guide: Get Involved in Markets+ on SPP.org
- Markets+ Service Offering
- Final Markets+ Tariff - April 18
- Exhibit 1 Phase 2 - 11.10.25
- Markets+ History & Phase One Participants
- Markets+ Protocols Production

RELATED DOCUMENT GROUPS

- Markets+ Documents
- Markets+ Program Materials
- Markets+ Initiative Requests

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	)

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

Exhibit 2-168
Tri-State Extreme Weather Event Modeling Assumptions

Colorado PUC E-Filings System

Extreme Weather Sensitivity

A dispatch sensitivity is modeled to simulate Extreme Weather Event (EWE) impacts and duration, and to evaluate system reliability. The following modeling inputs will be used to simulate EWEs:

Table 1: EWE Modeling Inputs

Assumption Item	Phase I Description	Phase II Description
Load	Gross up the extreme weather week by using the change in temperature and precipitation from actual storm event months compared to 10-year weather normalized load. Apply the monthly increase to the EWE week using the historical EWE weather patterns/shapes from the event, adjusted for known Member departures. Weather and patterns are calculated at the planning region level.	Continued approach of Phase I storm event load stress methodology during the Resource Acquisition Period (RAP), through 2031. For Post-RAP period, starting in 2032, selection of events from applicable EWE Database[1] Tier 2 or 3 events (identified below). The winter stress will continue to utilize the modeling approach used in Phase I. The summer EWE event utilizes the base load forecast, rather than reflecting the Phase I EWE load stress methodology to ensure a reasonable resource stress.
Load Forecast and EWE Period	EWE dates in January and July aligned the date of peak load in the storm shape with the peak load in the base forecast.	EWE dates in January and July will be selected to align the day of week of the storm shape with the day of the week of the load forecast. The EWE dates will be chosen such that the 168-hour EWE events modeled will overlay the date of the forecasted monthly peak for the base load forecast for the Western Interconnect.

[1] In 2024, Tri-State procured a third-party (Astrape) "EWE Study" and database of historical EWE events ("EWE Database") to inform the EWE simulation.

Assumption Item	Phase I Description	Phase II Description
Gas Prices	Winter EWE gas prices range from $5 to $200/MMBtu which reflects Winter Storm Uri (Feb. 11-17, 2021) pricing. Summer EWE gas prices range from $6 to $8/MMBtu which reflects Summer EWE event (July 17-23, 2022) pricing.	No change.
Power Prices	The historical purchase and sales hourly weighted average price of all zones and take the highest hourly price between purchase and sales. For hours with neither a historical purchase nor sale, the highest price between transactions was used. Maximum price during Winter events (Feb. 11-17, 2021) is $800/MWh and the maximum price during summer events (July 17-23, 2022) is $258/MWh.	No change.
TOT 3	Derated to 75% of maximum capacity for all hours of three days in the winter EWE period. Derated to 75% of maximum capacity for hours ending 16-21 during the summer EWE period.	No change.
Wind and Solar Resource – Net Availability	Stressed profiles were created for existing, under contract, bid, and generic resources. • *Winter Stress:* Observed data from Winter Storm Uri, actual generation used for existing units, representative irradiance and wind data used for generic and new generation not yet online. Additional stress of 50% for ECO, 80% for WCO, WYO, and NM for a 72-hour period during days 2-4 of the stressed period. • *Summer Stress:* Observed data from summer 2022 heat wave actual generation used for existing units, representative	2026-2031: • *Winter Stress:* Observed data from Winter Storm Uri, actual generation used for existing units, representative irradiance and wind data used for bid and new generation not yet online. Additional stress of 50% for ECO, 80% for WCO, WYO, and NM for a 72-hour period during days 3-5 to better align with peak during EWE event considering member departures. • *Summer Stress:* No change.

Assumption Item	Phase I Description	Phase II Description
	irradiance and wind data used for generic and new generation not yet online. Additional stress on solar profiles of 50% for ECO, WCO, and NM. Additional stress on wind profiles of 50% for ECO and NM and 80% for WYO for a 72-hour period during days 1-3 of the stressed period.	2032-2043: Stressed profiles were selected from the EWE Database for existing, under contract, bid and generic resources. • *Winter Stress:* Observed data from 1/8/2011-1/14/2011 Tier 3 Extreme Load Event. • *Summer Stress:* Observed data from 7/25/18-7/31/18 Tier 2 Net Load Event.
Dispatchable Resources	• *Winter stress:* Outages and derates for existing thermal coal and gas units will match the 2/11/2021 to 2/17/2021 event. • *Summer stress:* Outages and derates for existing thermal coal and gas units will match the 7/17/2022 to 7/23/2022 event.	2026-2031: No change. 2032-2043: • *Winter stress:* Derates of 9% applied to existing gas units for hours of EWE where system-weighted temperatures are below 0F degrees. • *Summer stress:* Derates of 1% applied to existing gas units for hours of EWE were system-weighted temperatures are above 95F degrees.
Market Depth (Purchases)[2]	Determined hourly purchase volumes for EWEs, at the market area level, based on historical activity; allowing market purchases during limited hours and markets of EWEs as follows: • Winter – NM Market allowed HE2-HE6; HE11-HE15; all other markets are closed for purchases. Hourly market depth of 60 MW.	No change.

[2] Market sales are open in the modeling.

Assumption Item	Phase I Description	Phase II Description
	○ Day 4 of EWE event, no purchase market available • Summer – ECO, WCO, WYO Markets allowed HE2-HE13; NM market closed for purchases. Hourly market depth of 70 MW. ○ Day 1 of EWE event, no purchase market available	

Summary of EWE Stress

Key features of RAP-period EWE Events:

- 168-hr event:
  - Winter EWE based on Storm Uri (Feb. 11-17, 2021).
    - Additional stress on resources 50% for ECO, 80% for WCO, WYO, and NM for a 72-hour period during days 3-5.
  - Summer EWE based on prior event (July 17-23, 2022).
    - Additional stress on solar profiles of 50% for ECO, WCO, and NM; and
    - Additional stress on wind profiles of 50% for ECO and NM and 80% for WYO for a 72-hour period during days 1-3.
- The dates of the storm shape are inclusive of the peak load in the base forecast for both Winter and Summer EWE. Summer peak loads are highest on days 1-3 and 5-6. Day 6 has the highest peak EWE load, but since the three-day period of days 1-3 have higher peak loads than a three-day period including Day 6, the additional renewable stress is on Days 1-3.

Key features of Post-RAP period EWE Events:

- 168-hr event:
  - Winter EWE based on Tier 3 Extreme Load Event (Jan. 8-14, 2011).
  - Summer EWE based on Tier 2 Net Load Event (July 25-31, 2018).
- Aligned the date of the forecasted monthly peak for the base load forecast for the Western Interconnect to fall within the storm shapes for both Winter EWE and Summer EWE.

Stressed Resource and Load Profiles for EWE Sensitivity Analysis

The adjustments made to create simulated EWE "stressed" profiles for existing, under contract, bid and generic resources, load, and transmission are described herein.

The EWEs for each portfolio were assumed to be one week (168 hours) in January and one week (168 hours) in July of each year, from 2026 to 2043.[3] The specific 168 hours were selected to align the day of the week between the forecast calendar and the storm shape, while overlapping with the monthly peak load for the Western Interconnect in the forecast in each modeled storm event.

Level II reliability target checks were performed on each portfolio's EWE sensitivity result, including:

- ≤ 12 loss of load hours combined during all EWEs in 2026-2031 (the resource acquisition period)
- ≤ 3 loss of load hours per year without available capacity
- EUE must be ≤ 20% of load in any hour
- Evaluation of market purchases vs remaining hourly available dispatchable capacity to ensure that EUE was not avoided through the use of market purchases as capacity.

Level II reliability metrics for each portfolio are identified in Attachment E.

Load Stress

To simulate the load stress that may occur during an EWE event, actual monthly energy by planning region for the storm month will be compared to weather normalized load values for the month in which the historical event occurred on the Western Interconnect. The weather normalization model specification includes precipitation and heating- and cooling-degree-days. Monthly increases in energy are derived from these statistical models and the differences are applied to the EWE week using the corresponding historical weather event shape by region and season for each forecasted 168-hour EWE event. In the summer EWE forecasts for the post-RAP period, the load reflects base weather normalized load to ensure the EWE stress is not unreasonably low, below the base load forecast. The historical shapes are adjusted to reflect the expected departures of Members on the Western Interconnect.

The load stress approach for the EWE sensitivity is both reasonable and robust. It is reasonable because it is using actual weather events to estimate load changes and align load and resource shapes. It is robust because it is assumed that differences in the weather models over a one-month period are correlated to extreme weather in the 168-hour period. The methodology utilized is consistent with the EWE load stress modeling approach in 2023 ERP Phase I. For the summer post-RAP period, we retain base, weather normalized shapes to prevent the extreme load stress from being unreasonably low in order to support a reasonable stress.

[3] Tri-State modeled the EWE Sensitivity across 2026-2043, with 2024 having already concluded and being already into 2025, with those years also being outside of the Resource Acquisition Period (RAP).

Gas Prices

Tri-State utilized gas price index data from its Energy Trading and Risk Management system for applicable events to arrive at pricing. See Table 1 above.

Power Prices

Tri-State utilized transactional data from its Energy Trading and Risk Management system for historical EWE events to arrive at stressed power pricing. Actual purchase and sales price data during historical EWE events was analyzed. The weighted average price between the following zones was calculated for each hour: FOURCORNER345, CRG, BOZ, AU, SPRINGER345, SJ345, SGW, DJ, and MIDWAY. These zones represent the four market areas in the EnCompass model: Eastern Colorado (ECO), New Mexico (NM), Western Colorado (WCO), and Wyoming / West Nebraska (WY/WNE). A weighted average was calculated for both purchases and sales. The maximum purchase/sale price was used for the EWE interval price. For hours where there were no transactions, a price based on the higher of the pre- or post- non-transaction hours was used. Each market area has the same market price for the hour to prevent arbitrage between the markets. See Table 1 above.

Transmission Stress

TOT3 is derated to 75% of maximum capacity for all hours of three days in the Winter EWE period. TOT3 is derated to 75% of maximum capacity for hours ending 16-21 for seven days in the Summer EWE period. The winter derate is based on patterns seen during Storm Uri. The summer derate is based on typical unscheduled flow impacts during high load, hot summer days.

Wind and Solar Stress Levels

The wind and solar resource capacity was modified in the EWE periods modeled to represent an assumed change in renewable unit performance anticipated during an extreme weather event across the Tri-State system. The stressed profiles are reflective of unit performance that were the result of the impacts of extreme weather previously observed through the historical data, as well as recognizing the statement made in Commission Decision No. C23-0437 (Proceeding No. 20A-0528E) in Paragraph 57, "…history may not be fully predictive of future weather extremes..." The historical extreme weather events used during the resource acquisition period (RAP) for renewables modeling were Winter Storm Uri in February 11-17, 2021 and a heat wave event that occurred in July 17-23, 2022. During the RAP an additional stress was applied for wind and solar in summer and winter, for a 72-hour period. Post-RAP renewable shapes are applied as defined in the EWE Database for the applicable timeframe defined in Table 1. The renewable stresses reflect system diversity by applying unique assumptions for each planning region.[4]

Wind

Severe weather can have a detrimental impact on wind generation, caused by factors such as low wind, icing, or maintenance issues. To ensure that the wind profiles accurately reflect extreme weather

[4] Wind is not modeled in as a resource in WCO.

conditions on the system, Tri-State utilized actual observed generation and weather conditions as a baseline for the EWE, where available.

RAP Period

For wind generation facilities that were online during the historical extreme weather events, Tri-State used actual metered generation output recorded in its SCADA system. In cases where generation had been contracted but not yet online, and for generic wind units, Tri-State relied on regional weather and wind data to estimate the output from facilities and then applied an additional stress to that output. To obtain the wind data, Tri-State used Visual Crossing data for a representative site in each generation area, and then applied a power curve developed by the National Renewable Energy Laboratory (NREL) based on data from two commercially available onshore IEC Class I machines to convert wind speed data into hourly generation.

Post-RAP Period

Tri-State used applicable profiles as defined in the EWE Database.

Winter

During the RAP, for a 72-hour period within the EWE, the WY/WNE and NM planning regions' wind resource profiles are stressed down by 80% and stressed down by 50% in the ECO planning region, as shown in Attachment E-1. Post- RAP Tri-State used applicable profiles as defined in the EWE database which was observed data from 1/8/2011-1/14/2011 Tier 3 Extreme Load Event.

Summer

During the RAP, for a 72-hour period within the EWE, the WY/WNE planning region wind resource profile is stressed down by 80%; and stressed down by 50% in NM and ECO planning regions, as shown in in Attachment E-1. Post-RAP, Tri-State used applicable profiles as defined in the EWE Database, which was observed data from 7/25/18-7/31/18 Tier 2 Net Load Event.

12Solar

During winter months, solar capacity profiles tend to decrease due to limited daylight, and weather conditions such as prolonged cloud cover can also have an impact.

During the RAP, to illustrate the effect of historical extreme weather on solar generation, Tri-State utilized actual generation data as recorded by SCADA and retained in OSIsoft PI for existing solar units and then applied an additional stress. In cases where generation had been contracted but not yet online, and for generic solar units, Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) irradiance data were used to estimate expected solar generation. Tri-State obtained this solar data from Visual Crossing and the NREL National Solar Radiation Database, and then used the NREL System Advisory Model (SAM) to simulate hourly power generation from photovoltaic (PV) arrays. Representative sites were selected from each planning region for this analysis. Post-RAP, Tri-State used applicable profiles as defined in the EWE Database.

Winter

During the RAP, WCO and NM planning regions' solar resource profiles are stressed down by 80% and stressed down by 50% in ECO planning region. Post-RAP, Tri-State used applicable profiles as defined in the EWE Database, which was observed data from 1/8/2011-1/14/2011 Tier 3 Extreme Load Event.

Summer

During the RAP, for a 72-hour period within the EWE, WCO NM and ECO planning regions' solar resource profiles are stressed down by 50%. Post-RAP, Tri-State used applicable profiles as defined in the EWE Database, which was observed data from 7/25/18-7/31/18 Tier 2 Net Load Event.

Dispatchable Resources

During the RAP, outages and derates for existing thermal coal and gas units reflect the 2/11/2021-2/17/2021 event for the Winter EWE. Outages and derates for existing thermal coal and gas units reflect the 7/17/2022-7/23/2022 event for the Summer EWE. Post-RAP, Winter EWE reflects derates of 9% applied to existing gas units for hours of EWE where system-weighted temperatures are below 0F degrees; and Summer EWE reflects derates of 1% applied to existing gas units for hours of EWE were system-weighted temperatures are above 95F degrees.

Market Depth Purchases

Tri-State reviewed transactional activity system for applicable events in its Energy Trading and Risk Management to determine likely hours with availability of market power for purchasing by planning region and related market depths. See Table 1 above.

While Day 6 of the EWE is the peak load day in the summer, no market purchases are on Day 1 of the EWE. Day 4 is the peak load day in the winter; therefore, Tri-State assumed that during the height of the EWE that no market purchases would be possible due to operational constraints likely occurring for all utilities in the region.

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	)

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

Exhibit 2-169
Colorado PUC Press Release, Feb. 18, 2026

Select Language

COLORADO

Department of Regulatory Agencies (/)

Public Utilities Commission

Home (/) Colorado Public Utilities Commission Approves New Energy Resources for Xcel Energy

Colorado Public Utilities Commission Approves New Energy Resources for Xcel Energy

February 18, 2026 - The Colorado Public Utilities Commission (PUC) today approved up to 4,100MW of new energy generation for Xcel Energy. The ten projects approved include a mix of solar, storage, wind, and natural gas. A final, written decision will be issued in the coming weeks.

These projects were approved as part of a stand-alone expedited process, termed the Near Term Procurement or NTP, Proceeding No. 21A-0141E, which was established to take advantage of expiring federal tax credits. In 2025, Congress passed H.R. 1 Act which set new, earlier expiration dates for renewable energy projects.

“Today’s action locks in cost savings for Xcel customers as we work to replace aging coal plants and meet growing energy demand,” said Rebecca White, Director of the Public Utilities Commission. “This was an extraordinary effort on the part of multiple stakeholders to bring these projects forward quickly in order to leverage expiring tax credits and save ratepayers billions. The Commission, in turn, closely reviewed these projects on a very tight timeline to ensure the best mix possible for ratepayers.”

In September of 2025, the Utility Consumer Advocate, Colorado Energy Office and Public Utility Commission staff joined Xcel Energy in proposing projects for accelerated review by the Commission. Today’s approval moves 3,200 MW in projects immediately forward with a potential of an additional 600-900 MW. Three of the projects approved today will be located in “just transition” communities impacted by the planned closure of coal-fired power plants.

The Commission’s approval is part of a broader effort across State Government to streamline and accelerate the development of eligible clean energy projects to provide reliable, affordable energy.

More information on Proceeding No. 21A-0141E can be found in E-Filings (https://www.dora.state.co.us/pls/efi/EFI.homepage).

Recent

April is National 9-1-1 Education Month (/press-release/april-is-national-9-1-1-education-month)
April 1, 2026 - The Colorado Public Utilities Commission (PUC) and the Division of Homeland Security and Emergency Management (DHSEM) are proud to announce participation in two vital public safety…

Governor Jared Polis Declares April 2026 'Dig Safely Month' (/press-release/governor-jared-polis-declares-april-2026-dig-safely-month)
March 31, 2026 - Governor Jared Polis Declares April 2026 'Dig Safely Month' to Mark 40th Anniversary of Colorado 811 State encourages all Coloradans to contact 811 before any excavation project to…

Colorado Public Utilities Commission Announces April Public Comment, Information and Engagement Opportunities (/press-release/colorado-public-utilities-commission-announces-april-public-comment-information-and)
March 26, 2026 - The Colorado Public Utilities Commission (PUC) is committed to informing and engaging the public in the matters before the Commission, and values perspectives from impacted community…

Contact Information

Colorado Public Utilities Commission
1560 Broadway, Suite 250, Denver, CO 80202
Phone: 303-894-2000 | Permits and Insurance: 800-888-0170 (Outside Denver)
Consumer Assistance: 303-894-2070 or 800-456-0858 (Outside Denver)
Fax: 303-894-2065
Email: dora_puc_website@state.co.us (mailto:dora_puc_website@state.co.us)

Quick Links

File a Complaint or Comment (https://docs.google.com/forms/d/e/1FAIpQLSclWDeNS2FCh0NdEijNU4igpUKqRZvTIYwZ8XSA2YYx3LF6qA/viewform)

News and Media (/newsreleases)

Accessibility Statement

Request a Cost-Benefit Analysis

Decision Index (/resource-library-index)

© 2026 State of Colorado | Transparency Online (https://data.colorado.gov/stories/s/fjyf-bdat) | General Notices (https://www.colorado.gov/general-notices)

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	)

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

Exhibit 2-170
Colorado PUC Feb. 2026 Decision

Decision No. C26-0117

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 ADDRESSING APPLICATIONS FOR REHEARING, REARGUMENT, OR RECONSIDERATION OF COMMISSION DECISION NO. C26-0081

Issued Date: February 23, 2026
Adopted Date: February 18, 2026

TABLE OF CONTENTS

I. BY THE COMMISSION 2
A. Statement 2
B. Procedural History 2
C. RRRs 4
1. State Agencies 4
2. Interwest 5
3. CIEA 6
4. Public Service 7
D. Findings and Conclusions 9
II. ORDER 14
A. The Commission Orders That: 14
B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING February 18, 2026. 15

Colorado PUC E-Filings System

I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission addresses the Application for Rehearing, Reargument, or Reconsideration ("RRR") of Decision No. C26-0081 that Trial Staff of the Commission, the Colorado Energy Office, and the Colorado Office of the Utility Consumer Advocate (collectively the "State Agencies") jointly filed on February 9, 2026, as well as the RRRs filed on February 13, 2026, by Public Service Company of Colorado ("Public Service" or the "Company"), Interwest Energy Alliance ("Interwest"), and Colorado Independent Energy Association ("CIEA").

B. Procedural History

2. On August 22, 2025, the State Agencies and the Company filed a Joint Motion to Initiate a Near-Term Procurement ("Motion to Initiate NTP").

3. Through Decision No. C25-0652-I, issued September 8, 2025, the Commission granted, with modifications, the Motion to Initiate NTP.

4. Public Service filed its NTP Motion and the accompanying NTP Report on December 5, 2025.

5. The Commission held the technical conference on December 18 and 19, 2025.

6. On January 12, 2026, several parties filed timely responses or comments to the NTP Motion and NTP Report.

7. Public Service filed its Unopposed Motion for Leave to File Reply Comments and Reply Comments on January 23, 2026.

8. The Commission deliberated on this matter at the January 28, 2026 Commissioners' Weekly Meeting ("CWM").

9. In response to the Commissioners' deliberations at the January 28 CWM, but prior to issuance of the Commission's written decision, the State Agencies and Interwest filed an Emergency Motion Requesting Decision Approving Near-Term Procurement Resources ("Emergency Motion") on February 3, 2026. At a high level, the Emergency Motion asked the Commission to change the outcome of its oral deliberations and approve either the State Agencies' proposed NTP portfolio or the Company's proposed NTP portfolio.

10. The Colorado Solar and Storage Association and Solar Energy Industries Association ("COSSA/SEIA"), the Natural Resources Defense Council and Sierra Club (collectively, "Conservation Coalition"), and Public Service, respectively, filed responses in support of the Emergency Motion on February 3, 2026.

11. Through Decision No. C26-0081, issued February 5, 2026, the Commission granted, in part, and denied, in part, the Motion to Acquire NTP Resources ("NTP Decision").

12. The State Agencies jointly filed a RRR of Decision No. C26-0081 on February 9, 2026.

13. Through Decision No. C26-0095, issued February 11, 2026, the Commission denied the Emergency Motion as untimely and procedurally inappropriate.

14. In our NTP Decision, as it relates to the projects included within the approved NTP portfolio of resources, the Commission approved the following for immediate contracting and procurement: Bid 053, Bid 054, Bid 034, Bid 135, Bid 099, and Bid 113. However, the Commission deferred selecting among Bid 046, Bid 055, Bid 094, Bid 089, Bid 003, Bid 118, and Bid 056 for inclusion in the approved NTP portfolio until after Public Service provides additional clarity regarding the business case for moving forward with these various projects. The Commission set a deadline of March 2, 2026, for Public Service to provide this additional

analysis, which includes a 10-year forecast when the key Denver Metro substations comprising the

Denver Metro transmission constraint are projected to be fully loaded. In addition, the Commission conditioned approval of Bid 127 until after the Company filed updated Encompass modeling on April 2, 2026.[1]

15. On February 13, 2026, Public Service, Interwest, and CIEA each filed a RRR to the NTP Decision.

C. RRRs

1. State Agencies

16. In the State Agencies' RRR, they ask the Commission to reconsider the NTP Decision to require additional new analysis and instead approve a final resource portfolio at the Commissioner's February 11, 2026 CWM. They argue that each passing day without a final decision increases the risk that projects will not be able to qualify for the federal tax credits.

17. The State Agencies further argue the NTP Decision creates an unnecessary new process that was not contemplated by the Motion to Initiate the NTP. They cite the Commission decision approving, in part, the Motion to Initiate NTP and argue that if the Company had known in advance that the Commission desired to see a spreadsheet analysis of the benefits of locating bids inside versus outside the Denver Metro Area, it could have provided this analysis as part of its NTP Report. Because the Commission did not request this analysis in advance, the State Agencies assert the Commission should reconsider how its belated request will cause timeline delays and ultimately risk the procurement of tax-advantaged projects.[2]

[1] Decision No. C26-0081 at ¶ 80.
[2] State Agencies RRR at p. 11.

18. The State Agencies similarly argue the Commission's directives regarding Bid 127 are contrary to the Motion to Initiate the NTP, which contemplates that Public Service will not conduct additional EnCompass modeling given the timing. They also argue the Commission failed to establish what criteria it would use to determine if the results of the EnCompass modeling warrant approving Bid 127.

19. As for the requested spreadsheet analysis, the State Agencies warn the Company may be unable to provide the requested analysis on hourly transmission constraints without additional modeling. The State Agencies note that such transmission modeling was not provided in Proceeding No. 24A-0560E, which evaluated a proposed transmission investment to help address the Denver Metro constraint.[3]

20. Regardless, the Stage Agencies argue that even if the Company is able to timely provide the requested analysis, it will still take time for the Commission to analyze the results, make decisions, and process any subsequent RRR that may arise. They argue that each delay makes it more difficult for developers to qualify for tax credits.

21. The State Agencies ultimately recommend the Commission unconditionally approve the State Agencies' NTP portfolio or the Company's Tier 1 portfolio. The State Agencies only recommend additional analysis if the Commission first approves the State Agencies' preferred portfolio but also wants to enlarge the portfolio with additional projects.[4]

2. Interwest

22. Like the State Agencies, Interwest requests that the Commission expeditiously approve as large of an NTP portfolio as possible, which could include the remaining projects in

[3] State Agencies RRR at p. 12.
[4] State Agencies RRR at pp. 16-17.

either the State Agencies' or the Company's NTP portfolio. According to Interwest, there is no evidence that the Commission's requested analysis exists or can be created, and on what timeline. Interwest argues that the uncertainty at this late stage is sending the exact opposite signal to the market that the NTP was designed to send and that developers will prioritize projects wherever certainty exists.

23. Interwest warns that that "billions of dollars" of expiring tax credits are at stake, and the Commission risks losing out on the benefit of the tax credits and spending more on the same or similar projects in future solicitations.[5] Interwest adds that the analysis of which projects can reliable retire the coal plants is better suited for the Just Transition Solicitation ("JTS") procurement in Proceeding No. 24A-0442E, as the NTP is designed to maximize cost effective, tax credit eligible resources in a one-time opportunity that is quickly expiring.

3. CIEA

24. CIEA likewise argues the Commission should quickly approve Public Service's full Tier 1 portfolio. Among other points, CIEA argues it is far from certain that the additional analysis thee Commission requested will even be available or accurate on such an expedited timeline. CIEA adds that the rushed timeframe of the additional analysis will likely not allow for party feedback. According to CIEA, "if the Commission allows locational factors such as the Denver Metro Constraint to be analyzed in the NTP, it cannot do so without allowing scrutiny of the Company's analytical methods given that the Company has now seen the available bids, and heard them discussed by the Commissioners."[6] CIEA adds the NTP was not initiated for the sole purpose of grid optimization, it was also aimed at a just transition and that the Commission should

[5] Interwest RRR at p. 3.
[6] CIEA RRR at p. 10.

not disregard siting projects in just transition communities in favor of projects within the Denver Metro constraint.[7]

25. More generally, CIEA argues that a prolonged proceeding risks the underlying goal of quickly acquiring clean energy resources. CIEA reiterates how this goal was set forth in the Motion to Initiate the NTP that Public Service and the State Agencies initially filed as well as the August 1, 2025 letter from Governor Polis.[8] CIEA argues that with additional delays, developers may repurpose safe-harbored equipment to other states. The possibility of losing the expiring tax credits outweighs the benefits of attempting further optimization. CIEA adds that it "reserves its right to file subsequent [RRR] seeking relief associated with project delays if the Commission's decision approving a final portfolio is issued significantly later than the date expected by [developers] when formulating bids and tax credit qualification strategies."[9]

26. CIEA avers that one of its members has reported that for at least two projects being actively considered by the Commission, the levelized energy cost that could be offered for the same projects in the JTS would immediately increase by more than 50 percent if the projects lose eligibility for tax credits.[10]

4. Public Service

27. In its RRR, Public Service states that it continues to support the full Tier 1 NTP portfolio. The Company asserts the resources included in the Tier 1 portfolio are necessary to serve load under any forecast if the Company is to continue to make progress reducing overall emissions consistent with State policy.[11] The Company notes broad support for the full NTP portfolio and

[7] CIEA RRR at pp. 9-10.
[8] CIEA RRR at p. 3.
[9] CIEA RRR at p. 6.
[10] CIEA RRR at p. 8.
[11] Public Service RRR at p. 2.

states the independent power producer trade associations and environmental advocates "recognize the need for action now to avoid unnecessary project price increases and to secure tax benefits for customers before they expire."[12] According to Public Service: "If the State, the Company and our customers are going to seize upon huge tax benefits, the Commission must act under some uncertainties and without perfect information, just as in any other business environment."[13]

28. Public Service raises concerns with the delayed approval of certain resources, warning that any delay will likely increase costs, compromise commercial operation dates ("CODs"), and threaten project viability. The Company asserts that just because some projects may be able to safe harbor does not mean that they will remain available in a later solicitation, much less at the same price. On this point, the Company provides confidential bidder feedback indicating that certain renewable resources that were not included in the approved NTP portfolio will likely be more expensive in the future, delayed, and potentially unavailable.[14]

29. Regarding the Commission's stated transmission concerns, Public Service asserts that "there will be no way to solution the combined NTP/JTS Base portfolio to eliminate significant transmission infrastructure additions and improvements."[15] The Company references the JTS Direct and Rebuttal Testimony and NTP Reply comments for the point that additional transmission investments will be needed under all scenarios to continue integrating renewables onto the system to meet the 2030 statutory goal and beyond.

30. In addition to its concerns regarding the NTP portfolio, Public Service seeks clarification of the Commission's directive for additional analysis by March 2, 2026.

[12] Public Service RRR at p. 3.
[13] Public Service RRR at p. 5.
[14] Public Service RRR at p. 4.
[15] Public Service RRR at p. 3.

The Company states it will provide the requested spreadsheet analysis incorporating the $191/kW transmission constraint credit as soon as possible and will use such analysis to inform the business case analysis the Commission has requested. However, the Company asserts it cannot provide the 10-year forecast of the Denver Metro constraint because this "is not an off-the-shelf product."[16] The Company estimates that providing the 10-year transmission forecast the Commission requested "would require significantly more time - likely several months of detailed planning and analysis to complete." [17]

31. Nevertheless, the Company states it will provide the information it can by March 2, 2026, to help inform the Commission's conversation and that it is also analyzing other constraints, such as the constraint impacting the transmission corridor known as total of transmission ("TOT") 5. Public Service requests clarification that its plan for the March 2, 2026 filing is acceptable.

D. Findings and Conclusions

32. We grant, with modifications, in part, and deny, in part, the RRRs set forth above. We reiterate the difficulties of making such large investment decisions without better analysis regarding things like transmission investments, curtailments, and the optimal mix of resources. However, the arguments put forth in RRR have convinced us to move forward now with certain additional resource procurements. While we are disappointed the Company is unable to quickly provide the 10-year forecast of the Denver Metro constraint, we nevertheless appreciate the parties filing the RRRs as quickly as they did. The Commission is working to flexibly balance the need

[16] Public Service RRR at p. 6.
[17] Public Service RRR at p. 6.

for quick regulatory processes with the reality that these are complex decisions regarding large investments.

33. Specifically, we now include Bid 089 (a 500 MW power purchase agreement ("PPA") solar),[18] Bid 046 (a 400 MW PPA solar plus storage), and Bid 055 (a 200 MW PPA solar plus storage) within the approved NTP portfolio. All three of these projects are included within both the State Agencies' recommended portfolio as well as the Company's recommended portfolio. While we will continue to try to optimize the selection of generation resources in ways that can potentially reduce other system costs such as additional transmission investments and curtailments, we find it unlikely that these three projects will not be valuable to the system. Given the need for significant amounts of new generation, the favorable pricing of these projects, and the likelihood that their costs will increase in the near future, we find it appropriate to immediately include these projects in the approved portfolio.

34. At the same time, we defer including Bid 127 (a 608 MW Company-owned wind project) in the approved NTP portfolio until we are better able to compare it to Bid 094 (a 450 MW Company-owned solar plus storage project). While Bid 127 is included within the State Agencies' and the Company's recommended portfolios, we question whether this large wind project should be replaced with Bid 094, a large solar plus storage project. Bid 094 is included in the Company's Tier 2 backup portfolio, has a higher accredited capacity than Bid 127,[19] and is located within the Denver Metro constraint. Although Bid 127 has a lower scoring levelized cost

[18] While voting to unconditionally approve Bid 089, Chair Blank's first preference would be to conditionally approve Bid 094 instead, which would provide 450 MW of solar and 450 MW of storage within the Denver Metro constraint. Chair Blank is concerned about the Company's ability to rely on Bid 089 during periods of peak load because the 500 MW solar project is located outside of the Denver Metro constraint.

[19] *See* State Agencies' Response to NTP Motion, Attachment JPSA-1.

than Bid 094, the Company has indicated that without Encompass modeling it is difficult to compare the levelized cost of solar plus storage projects with other types of technologies.[20] Replacing Bid 127 with Bid 094 may also be warranted based on the pricing shifts experienced for wind projects as opposed to solar and storage projects. Similar to arguments the State Agencies make regarding excluding the four highest-cost wind projects from the NTP portfolio, computer-based modeling might show that a 450 MW solar plus storage resource is more valuable than a 608 MW wind resource.[21]

35. In addition, we remain concerned that the selection of Bid 127 does not account for the additional transmission investments that will be necessary to deliver the power into the Denver Metro constraint. While we acknowledge the Company's assertion that more transmission investment is likely necessary under any scenario, Bid 094's location within the Denver Metro constraint could reduce those transmission costs. After factoring in the $191/MW Denver Metro transmission credit, Bid 127 may be a higher cost than Bid 094.

36. In the upcoming March 2, 2026 analysis, Public Service will provide, among other things, a spreadsheet analysis incorporating the Denver Metro transmission constraint credit into the Scoring Levelized Energy Cost metric. This is the type of additional analysis that will better allow us to decide which project to include in the approved NTP portfolio. After we receive this analysis, the Commission will decide whether to select Bid 094, Bid 127, or whether to wait until the Commission has the April 2, 2026 EnCompass modeling.

37. As for Bid 118 (a 400 MW PPA storage project), the Company's arguments regarding transmission concerns do not persuade us to remove Bid 118 from the approved

[20] NTP Report at p. 40.
[21] *See* Decision No. C26-0081 at ¶¶ 65-67.

portfolio.[22] The NTP Report has several examples of bids being excluded from the Tier 1 and Tier 2 portfolios because of transmission concerns.[23] Moreover, the Company clarified in its Reply comments that it marked bids as "Failed" either when a project had insurmountable flaws for the NTP (like transmission development/interconnection risk) or for projects that would be better suited to the JTS Request for Proposals.[24] None of these concerns are set forth in the NTP Report for Bid 118. Rather, Public Service includes Bid 118 in its Tier 2 portfolio for which it sought Commission approval.

38. Public Service first discussed transmission concerns regarding Bid 118 at the technical conference. In addition to the transmission concerns regarding TOT 5, Company witness Mr. Landrum stated the storage project would use scarce interconnection capacity in that area and that it would be better to wait until the JTS when there is more competitive tension for those interconnection resources.[25] Given the NTP was an open source solicitation, we find the Company's arguments to wait for more competitive tension to be confusing.

39. In its Reply comments, Public Service provides more detail with respect to its transmission concerns regarding Bid 118, including statements it marks as highly confidential regarding its transfer rights in TOT 5.[26] These new details are again confusing given that Public Service will have the ability to choose when and how to charge and discharge Bid 118.

[22] The State Agencies include Bid 118 in their recommended portfolio. While the State Agencies position Bid 113 (a 300 MW PPA storage project) as an alternate to Bid 118, both projects have attractive pricing and locations (Bid 118 is located in a just transition community, and Bid 113 is located within the Denver Meto constraint). Given these positive attributes and the fact that our approved NTP portfolio has fewer wind resources than the Company's Tier 1 portfolio, we find it appropriate to include both Bid 113 and Bid 118 in the approved portfolio.

[23] *See, e.g.*, NTP Report at p. 51.

[24] Public Service Reply comments at p. 14.

[25] Hr. Tr. December 18, 2025, pp. 103-04.

[26] Public Service Reply comments at p. 18.

Moreover, Public Service's Reply statements appear to contradict the Company's written testimony in the JTS.[27]

40. While we are unpersuaded to defer Bid 118 until Phase II of the JTS, we do not ignore Public Service's concerns. Bid 118 is included in the approved portfolio subject to the additional transmission analysis the Company argues is necessary.[28] If, after additional analysis, the Company cannot move forward with the project, it can make an appropriate filing explaining its determination. Fortunately, given Bid 118's relatively early COD and low price, there is headroom for COD and price flexibility to allow the Company more time to analyze the transmission impacts. Public Service shall account for this flexibility during PPA negotiations with the developer of Bid 118. Finally, we encourage the Company to also provide the estimated property tax contributions from Bid 118, as such property taxes will be a material benefit to both the Routt County communities and Public Service ratepayers.

41. As for the Company's requested clarification regarding the additional analysis it must provide by March 2, 2026, we affirm the Company's plan as set forth in its RRR is acceptable, including the fact that it will not be able to provide the 10-year transmission forecast of the Denver Metro constraint. Given our RRR rulings set forth in this Decision, however, we further clarify that the March 2, 2026 analysis is only required for Bid 094, Bid 127, and Bid 118.[29]

42. In the NTP Decision, we asked Public Service include Bid 056 (a 200 MW PPA storage project) in the March 2, 2026 analysis. Bid 056 is intriguing given it is one of only a few

[27] Hr. Ex. 101, Attachment JWI-2, Volume 2, pp. 106-07 in Proceeding No. 24A-0442E.

[28] While voting to include Bid 118 in the approved NTP portfolio, similar to Bid 089 Chair Blank's first preference would have been to include Bid 118 as a backup and focus on Bid 094, which is located within the Denver Metro constraint.

[29] We recognize that Public Service may not be able to complete all of the required transmission analysis for Bid 118 by March 2, 2026, but look forward to whatever additional information the Company can provide consistent with its indications in RRR. (Public Service RRR at p. 7).

eight-hour storage projects as well as its price relative to gas units. Given our other RRR rulings and the fact that Bid 056 has not undergone the same due diligence review as other available options, however, we no longer are considering including Bid 056 in the approved NTP portfolio. Nevertheless, we remain intrigued about the apparent benefits of eight-hour storage projects, which have high effective load carrying capability values. In the 120-Day Report that will be filed in Phase II of the JTS, we encourage Public Service to discuss how eight-hour storage projects are comparable to thermal projects.

43. In conclusion, through this Decision we add Bid 089, Bid 046, and Bid 055 to the approved NTP portfolio. We include Bid 118 in the approved NTP portfolio subject to the additional transmission analysis the Company argues is necessary. After Public Service provides additional analysis, we may also include Bid 127 or Bid 094 in the approved NTP portfolio. When accounting for the projects included via Decision No. C26-0095, the approved NTP portfolio consists of the following bids: Bid 089, Bid 046, Bid 055, Bid 118, Bid 053, Bid 054, Bid 034, Bid 135, Bid 099, and Bid 113. The Company should immediately begin contracting and procurement associated with these projects. The Commission will determine whether to also include Bid 127 or Bid 094 in the approved NTP portfolio in a subsequent decision.

II. ORDER

A. The Commission Orders That:

1. The Application for Rehearing, Reargument, or Reconsideration ("RRR") of Decision No. C26-0081 that Trial Staff of the Commission, the Colorado Energy Office, and the Colorado Office of the Utility Consumer Advocate jointly filed on February 9, 2026, is granted, in part, with modifications, and denied, in part, consistent with the discussion above.

2. The RRR that Public Service Company of Colorado filed on February 13, 2026, is granted, in part, with modifications, and denied, in part, consistent with the discussion above.

3. The RRR that Interwest Energy Alliance filed on February 13, 2026, is granted, in part, with modifications, and denied, in part, consistent with the discussion above.

4. The RRR that the Colorado Independent Energy Association filed on February 13, 2026, is granted, in part, with modifications, and denied, in part, consistent with the discussion above.

5. 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.

6. This Decision is effective immediately upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING February 18, 2026.

(S E A L)

THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

ATTEST: A TRUE COPY

Rebecca E. White,
Director