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Exhibit 1

Order No. 202-25-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the electricity grid operated by PJM Interconnection (PJM) due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

PJM has recently stated its system faces "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[1] Upcoming retirements, including the planned retirement of Unit 3 and Unit 4 of the Eddystone Generating Station in Eddystone, Pennsylvania, will exacerbate these resource adequacy issues.

PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[2] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks,*" PJM highlights the increasing risk of reliability risk in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[3]

In December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[4] In March 2025 congressional testimony, PJM found "a growing resource adequacy concern" due to a combination of load growth, the retirement of dispatchable resources, and other factors.[5] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[6]

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[1] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[2] https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/
[3] https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx
[4] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250211-3120
[5] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[6] Ibid.

Constellation Energy owns the Eddystone Generating Station, which includes Unit 3 and Unit 4, each of which has a nameplate capacity of 380 MW. Units 3 and 4 have a planned retirement date of May 31, 2025. The retirement of these units would further decrease available dispatchable generation within PJM's service territory.

Pursuant to Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid* (EO 14262), DOE is developing a methodology to identify current and anticipated reserve margins for all regions of the bulk-power system regulated by the Federal Energy Regulatory Commission. EO 14262 requires this methodology to be published by July 7, 2025, and be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk-power system. DOE plans to use this methodology to further evaluate Eddystone Units 3 and 4.

ORDER

Given the emergency nature of resource adequacy concerns, the declared state of national energy emergency, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, operational availability and economic dispatch of the aforementioned Eddystone Units 3 and 4 (Eddystone Units) is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the potential load stress due to aforementioned resource adequacy concerns, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The potential shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the region support the need for the Eddystone Units to contribute to system reliability.
- PJM's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Eddystone Units, necessary to meet the load demands.

This Order is limited in duration to align with the anticipated emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse

environmental impacts. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 30, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that Eddystone Units are available to operate. For the duration of this order, PJM is directed to take every step to employ economic dispatch of the units to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

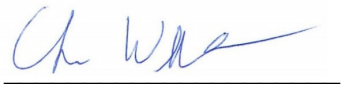
D. By June 15, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. In addition, PJM and Constellation Energy are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. This Order shall be effective upon its issuance, and shall expire at 5:03 PM EDT on August 28, 2025, with the exception of the reporting requirements in paragraph D.

H. Issued in Simi Valley, California, at 5:03 PM Eastern Daylight Time on this 30th day of May 2025.



Chris Wright
Secretary of Energy

Exhibit 2

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

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

Filed June 18, 2025

Exhibit 30

DOE Rehearing Procedures

U.S. DEPARTMENT of ENERGY

DOE 202(c) Order Rehearing Procedures

DOE may revise these procedures through advance written notification to the parties and posting here.

Intervention. Any person seeking to intervene to become a party must file a written motion to intervene by emailing AskCR@hq.doe.gov. A motion to intervene must state the movant's interest in sufficient factual detail to demonstrate that the movant has or represents an interest which may be directly and substantially affected by the outcome of the proceeding. A motion to intervene must be filed within 30 days after the

issuance of a section 202(c) order, which includes an original order or a renewal order. No grant of late intervention is permitted unless DOE finds good cause. The grant of party status will be expressly stated by DOE order within thirty days of filing. A motion to intervene may be combined with a motion for rehearing, answer, or other motion.

Rehearing. Pursuant to 16 U.S. Code § 825*l*, any party applying for rehearing must file a written motion for rehearing by emailing AskCR@hq.doe.gov within 30 days after the issuance of a section 202(c) order. The motion for rehearing must set forth specifically the ground or grounds upon which such motion is based and must contain a clear and concise statement of the facts and law which support the motion and the specific relief or ruling requested. Any grounds not specifically identified in such motion shall be waived. All motions for rehearing will be addressed in a consolidated proceeding and order on rehearing. Unless DOE acts upon the motion for rehearing within 30 days of filing, such motion may be deemed to have been denied.

Answers. Any party may file an answer to another party's motion by emailing AskCR@hq.doe.gov within 7 days after the motion is filed. An answer must contain a clear and concise statement of any disputed factual allegations and any law upon which the answer relies. An answer to an answer is not permitted.

Timing and Service. DOE will use best efforts to post filings here within 24 hours of receipt. Such posting constitutes service to all parties. Filing or posting due dates that fall on a federal holiday or weekend shall be extended to the next business day. Documents received after 4:30 p.m. Eastern Time are deemed filed on the next business day.

Confidentiality. DOE strongly encourages that all filings be limited to information suitable for public release. If procedures to maintain confidentiality are requested, DOE will provide them as needed at the discretion of DOE.

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USA.gov

The White House

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Exhibit 3

-----Original Message-----
From: Alle-Murphy, Linda
Sent: Wednesday, December 28, 2005 9:05 AM
To: Mansueti, Lawrence
Subject: Re: Order No. 202-05-3

Dear Mr. Mansueti,

I am an associate at Schnader Harrison Segal and Lewis, working together with John Britton, who represents the City of Alexandria in the Mirant Power Plant matter. I have a few procedural questions regarding the application for rehearing.

According to Section VI.H. of Order No. 202-05-3, applications for rehearing in this matter should be addressed to you. Section VI.H. cites to 16 U.S.C. Section 825(l), which refers to the "Commission" (FERC). I am just seeking to confirm that Section 825(l) also applies to this DOE proceeding.

Also, are 10 CFR Section 1003.1 et seq., Office of Hearings and Appeals Procedural Regulations applicable to this proceeding (e.g. re service requirements, etc.) If not, are there other procedural rules that apply to this proceeding?

Thank you very much for your assistance! You may respond by return e-mail or, if that is not convenient for you, by telephone or fax.

Linda Alle-Murphy
Linda B. Alle-Murphy
Schnader Harrison Segal & Lewis LLP
1600 Market Street, Suite 3600
Philadelphia, PA 19103-7286

From: Cooke, Lot
Sent: Friday, December 30, 2005 8:51 AM
To: 'LAlle-Murphy@Schnader.com'
Subject: Rehearing procedures for DOE Order No. 202-05-3

Dear Ms. Alle-Murphy:

In response to your emailed question to Mr. Mansueti--

The DOE Organization Act transferred the authority of the Federal Power Commission to the Secretary, except for authority over rates and charges for the transmission and sale of electric energy, which was transferred to FERC. Federal Power Act (FPA) Section 202(c) emergency authority was generally and specifically given to the Secretary.

An order issued under the FPA is only reviewable pursuant to the rehearing provisions contained in section 313 of the FPA, so that is the applicable provision under which to seek rehearing of the December 20,
2005 order.

The DOE regulations on emergency orders, 10 CFR section 205.370, et seq., do not a have specific rehearing section, but a party seeking rehearing can look for procedural guidance to FERC's Rules of Practice and Procedure, 18 CFR Part 385. In particular the rehearing regulations contained at 18 CFR section 385.713 and the service requirement contained at 18 CFR section 385.2010. The Office of Hearings and Appeals procedures are not applicable as the Secretary will make the rehearing decision pursuant to FPA section 313.

Exhibit 4

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM

TITLE V/STATE OPERATING PERMIT

Issue Date: April 17, 2025 Effective Date: April 17, 2025

Expiration Date: April 16, 2030

In accordance with the provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and 25 Pa. Code Chapter 127, the Owner, [and Operator if noted] (hereinafter referred to as permittee) identified below is authorized by the Department of Environmental Protection (Department) to operate the air emission source(s) more fully described in this permit. This Facility is subject to all terms and conditions specified in this permit. Nothing in this permit relieves the permittee from its obligations to comply with all applicable Federal, State and Local laws and regulations.

The regulatory or statutory authority for each permit condition is set forth in brackets. All terms and conditions in this permit are federally enforceable applicable requirements unless otherwise designated as "State-Only" or "non-applicable" requirements.

TITLE V Permit No: 23-00017

Federal Tax Id - Plant Code: 23-3064219-1

Owner Information

Name: CONSTELLATION ENERGY GENERATION LLC
Mailing Address: 1 INDUSTRIAL HWY
EDDYSTONE, PA 19022-1524

Plant Information

Plant: CONSTELLATION ENERGY GENERATION LLC/EDDYSTONE
Location: 23 Delaware County 23821 Eddystone Borough
SIC Code: 4911 Trans. & Utilities - Electric Services

Responsible Official

Name: PAUL WEEKS
Title: VP REGIONAL OPERATIONS
Phone: (610) 909 - 6626 Email: paul.weeks@constellation.com

Permit Contact Person

Name: JOSEPH M KUKLINSKI
Title: ENVIRONMENTAL SPECIALIST
Phone: (610) 595 - 8113 Email: joseph.kuklinski@constellation.com

[Signature] _____

JILLIAN A. GALLAGHER, SOUTHEAST REGION AIR PROGRAM MANAGER

SECTION A. Table of Contents

Section A. Facility/Source Identification

Section B. General Title V Requirements

Section C. Site Level Title V Requirements

Section D. Source Level Title V Requirements

SECTION A. Table of Contents

SECTION A. Site Inventory List

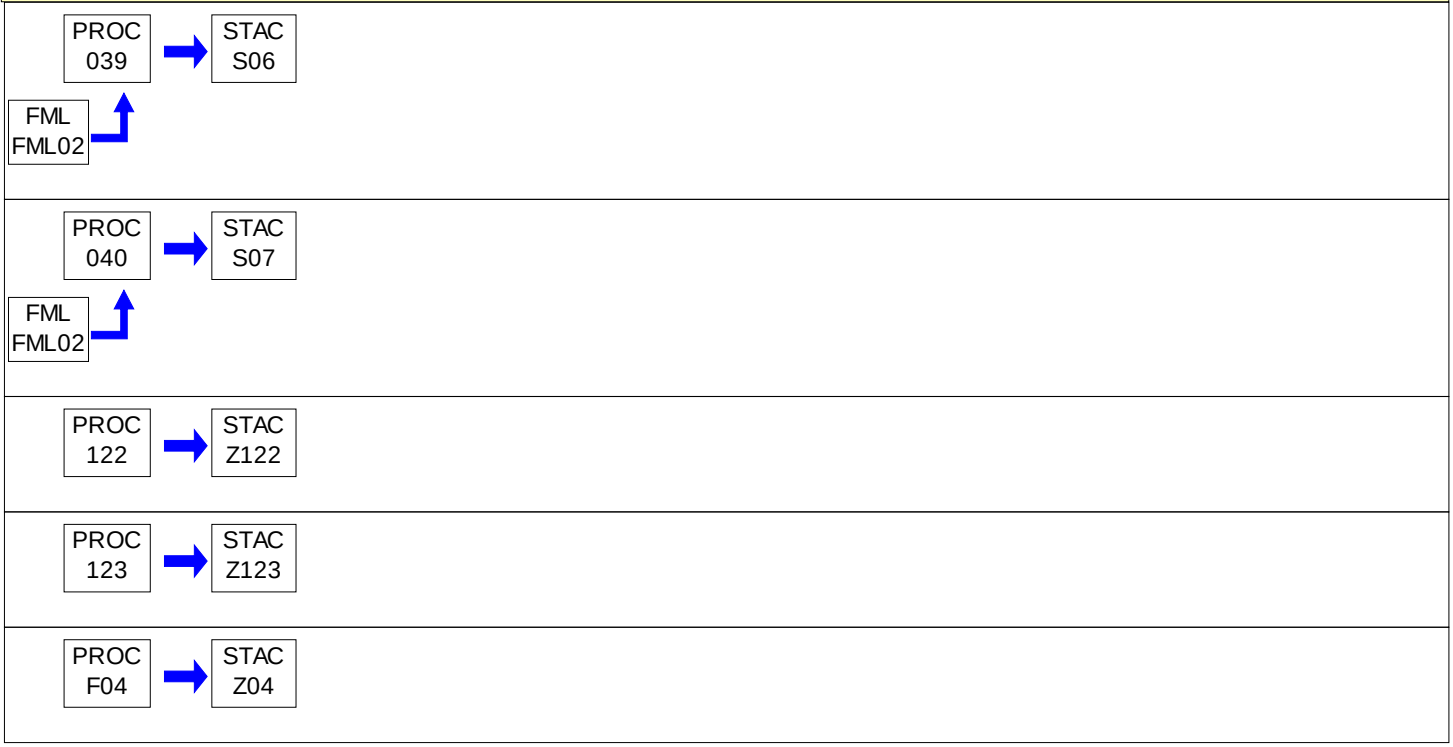
Source ID	Source Name	Capacity/Throughput		Fuel/Material
033	BOILER 3	4,116.000	MMBTU/HR	
		33,352.000	Gal/HR	#2 Oil
		4.480	MMCF/HR	Natural Gas
034	AUXILIARY BOILER A	124.000	MMBTU/HR	
		925.900	Gal/HR	#2 Oil
		122.300	MCF/HR	Natural Gas
035	AUXILIARY BOILER B	124.000	MMBTU/HR	
		925.900	Gal/HR	#2 Oil
		122.300	MCF/HR	Natural Gas
036	AUXILIARY BOILER C	124.000	MMBTU/HR	
		925.900	Gal/HR	#2 Oil
		122.300	MCF/HR	Natural Gas
041	BOILER 4	4,116.000	MMBTU/HR	
		33,352.000	Gal/HR	#2 Oil
		4.480	MMCF/HR	Natural Gas
037	NO. 10 COMBUSTION TURBINE	1,726.000	Gal/HR	Kerosene
		1,726.000	Gal/HR	#2 Oil
038	NO. 20 COMBUSTION TURBINE	1,726.000	Gal/HR	Kerosene
		1,726.000	Gal/HR	#2 Oil
039	NO. 30 COMBUSTION TURBINE	2,104.000	Gal/HR	Kerosene
		2,104.000	Gal/HR	#2 Oil
040	NO. 40 COMBUSTION TURBINE	2,104.000	Gal/HR	Kerosene
		2,104.000	Gal/HR	#2 Oil
122	#2 OIL STORAGE TANK (1.05 MMGAL)			
123	FUEL OIL STORAGE TANKS(2)			
F04	OIL DELIVERY FUGITIVES			
FML01	NATURAL GAS LINE			
FML02	#2 FUEL OIL			
S03	BOILER 3/4 STACK			
S04	TURBINE 10 STACK			
S05	TURBINE 20 STACK			
S06	TURBINE 30 STACK			
S07	TURBINE 40 STACK			
S08	AUX BOILER A STACK			
S09	AUX BOILER B STACK			
S10	AUX BOILER C STACK			
Z04	OIL HANDLING FUGITIVES			
Z122	OIL TANK FUGITIVES			
Z123	FUEL OIL STORAGE TANK(S) FUGITIVES			

PERMIT MAPS

PERMIT MAPS


CU 033
STAC S03
FML FML01
FML FML02
CU 034
STAC S08
FML FML01
FML FML02
CU 035
STAC S09
FML FML02
FML FML01
CU 036
STAC S10
FML FML02
FML FML01
CU 041
STAC S03
FML FML01
FML FML02
PROC 037
STAC S04
FML FML02
PROC 038
STAC S05
FML FML02

PERMIT MAPS


PROC 039
STAC S06
FML FML02
PROC 040
STAC S07
FML FML02
PROC 122
STAC Z122
PROC 123
STAC Z123
PROC F04
STAC Z04

SECTION B. General Title V Requirements

#001 [25 Pa. Code § 121.1]

Definitions

Words and terms that are not otherwise defined in this permit shall have the meanings set forth in Section 3 of the Air Pollution Control Act (35 P.S. § 4003) and 25 Pa. Code § 121.1.

#002 [25 Pa. Code § 121.7]

Prohibition of Air Pollution

No person may permit air pollution as that term is defined in the Air Pollution Control Act (35 P.S. §§ 4001-4015).

#003 [25 Pa. Code § 127.512(c)(4)]

Property Rights

This permit does not convey property rights of any sort, or any exclusive privileges.

#004 [25 Pa. Code § 127.446(a) and (c)]

Permit Expiration

This operating permit is issued for a fixed term of five (5) years and shall expire on the date specified on Page 1 of this permit. The terms and conditions of the expired permit shall automatically continue pending issuance of a new Title V permit, provided the permittee has submitted a timely and complete application and paid applicable fees required under 25 Pa. Code Chapter 127, Subchapter I and the Department is unable, through no fault of the permittee, to issue or deny a new permit before the expiration of the previous permit. An application is complete if it contains sufficient information to begin processing the application, has the applicable sections completed and has been signed by a responsible official.

#005 [25 Pa. Code §§ 127.412, 127.413, 127.414, 127.446(e), 127.503 & 127.704(b)]

Permit Renewal

(a) An application for the renewal of the Title V permit shall be submitted to the Department at least six (6) months, and not more than 18 months, before the expiration date of this permit. The renewal application is timely if a complete application is submitted to the Department's Regional Air Manager within the timeframe specified in this permit condition.

(b) The application for permit renewal shall include the current permit number, the appropriate permit renewal fee, a description of any permit revisions and off-permit changes that occurred during the permit term, and any applicable requirements that were promulgated and not incorporated into the permit during the permit term. The fees shall be made payable to "The Commonwealth of Pennsylvania Clean Air Fund" and submitted with the fee form to the respective regional office.

(c) The renewal application shall also include submission of proof that the local municipality and county, in which the facility is located, have been notified in accordance with 25 Pa. Code § 127.413. The application for renewal of the Title V permit shall also include submission of compliance review forms which have been used by the permittee to update information submitted in accordance with either 25 Pa. Code § 127.412(b) or § 127.412(j).

(d) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information during the permit renewal process. The permittee shall also promptly provide additional information as necessary to address any requirements that become applicable to the source after the date a complete renewal application was submitted but prior to release of a draft permit.

#006 [25 Pa. Code §§ 127.450(a)(4) & 127.464(a)]

Transfer of Ownership or Operational Control

(a) In accordance with 25 Pa. Code § 127.450(a)(4), a change in ownership or operational control of the source shall be treated as an administrative amendment if:

(1) The Department determines that no other change in the permit is necessary;

(2) A written agreement has been submitted to the Department identifying the specific date of the transfer of permit responsibility, coverage and liability between the current and the new permittee; and,

(3) A compliance review form has been submitted to the Department and the permit transfer has been approved by

SECTION B. General Title V Requirements

the Department.

(b) In accordance with 25 Pa. Code § 127.464(a), this permit may not be transferred to another person except in cases of transfer-of-ownership which are documented and approved to the satisfaction of the Department.

#007 [25 Pa. Code § 127.513, 35 P.S. § 4008 and § 114 of the CAA]

Inspection and Entry

(a) Upon presentation of credentials and other documents as may be required by law for inspection and entry purposes, the permittee shall allow the Department of Environmental Protection or authorized representatives of the Department to perform the following:

(1) Enter at reasonable times upon the permittee's premises where a Title V source is located or emissions related activity is conducted, or where records are kept under the conditions of this permit;

(2) Have access to and copy or remove, at reasonable times, records that are kept under the conditions of this permit;

(3) Inspect at reasonable times, facilities, equipment including monitoring and air pollution control equipment, practices, or operations regulated or required under this permit;

(4) Sample or monitor, at reasonable times, substances or parameters, for the purpose of assuring compliance with the permit or applicable requirements as authorized by the Clean Air Act, the Air Pollution Control Act, or the regulations promulgated under the Acts.

(b) Pursuant to 35 P.S. § 4008, no person shall hinder, obstruct, prevent or interfere with the Department or its personnel in the performance of any duty authorized under the Air Pollution Control Act.

(c) Nothing in this permit condition shall limit the ability of the EPA to inspect or enter the premises of the permittee in accordance with Section 114 or other applicable provisions of the Clean Air Act.

#008 [25 Pa. Code §§ 127.25, 127.444, & 127.512(c)(1)]

Compliance Requirements

(a) The permittee shall comply with the conditions of this permit. Noncompliance with this permit constitutes a violation of the Clean Air Act and the Air Pollution Control Act and is grounds for one (1) or more of the following:

(1) Enforcement action

(2) Permit termination, revocation and reissuance or modification

(3) Denial of a permit renewal application

(b) A person may not cause or permit the operation of a source, which is subject to 25 Pa. Code Article III, unless the source(s) and air cleaning devices identified in the application for the plan approval and operating permit and the plan approval issued to the source are operated and maintained in accordance with specifications in the applications and the conditions in the plan approval and operating permit issued by the Department. A person may not cause or permit the operation of an air contamination source subject to 25 Pa. Code Chapter 127 in a manner inconsistent with good operating practices.

(c) For purposes of Sub-condition (b) of this permit condition, the specifications in applications for plan approvals and operating permits are the physical configurations and engineering design details which the Department determines are essential for the permittee's compliance with the applicable requirements in this Title V permit.

#009 [25 Pa. Code § 127.512(c)(2)]

Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

SECTION B. General Title V Requirements

#010 [25 Pa. Code §§ 127.411(d) & 127.512(c)(5)]

Duty to Provide Information

(a) The permittee shall furnish to the Department, within a reasonable time, information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit.

(b) Upon request, the permittee shall also furnish to the Department copies of records that the permittee is required to keep by this permit, or for information claimed to be confidential, the permittee may furnish such records directly to the Administrator of EPA along with a claim of confidentiality.

#011 [25 Pa. Code §§ 127.463, 127.512(c)(3) & 127.542]

Reopening and Revising the Title V Permit for Cause

(a) This Title V permit may be modified, revoked, reopened and reissued or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay a permit condition.

(b) This permit may be reopened, revised and reissued prior to expiration of the permit under one or more of the following circumstances:

(1) Additional applicable requirements under the Clean Air Act or the Air Pollution Control Act become applicable to a Title V facility with a remaining permit term of three (3) or more years prior to the expiration date of this permit. The Department will revise the permit as expeditiously as practicable but not later than 18 months after promulgation of the applicable standards or regulations. No such revision is required if the effective date of the requirement is later than the expiration date of this permit, unless the original permit or its terms and conditions has been extended.

(2) Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator of EPA, excess emissions offset plans for an affected source shall be incorporated into the permit.

(3) The Department or the EPA determines that this permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.

(4) The Department or the Administrator of EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(c) Proceedings to revise this permit shall follow the same procedures which apply to initial permit issuance and shall affect only those parts of this permit for which cause to revise exists. The revision shall be made as expeditiously as practicable.

(d) Regardless of whether a revision is made in accordance with (b)(1) above, the permittee shall meet the applicable standards or regulations promulgated under the Clean Air Act within the time frame required by standards or regulations.

#012 [25 Pa. Code § 127.543]

Reopening a Title V Permit for Cause by EPA

As required by the Clean Air Act and regulations adopted thereunder, this permit may be modified, reopened and reissued, revoked or terminated for cause by EPA in accordance with procedures specified in 25 Pa. Code § 127.543.

#013 [25 Pa. Code § 127.522(a)]

Operating Permit Application Review by the EPA

The applicant may be required by the Department to provide a copy of the permit application, including the compliance plan, directly to the Administrator of the EPA. Copies of title V permit applications to EPA, pursuant to 25 PA Code §127.522(a), shall be submitted, if required, to the following EPA e-mail box:

R3_Air_Apps_and_Notices@epa.gov

Please place the following in the subject line: TV [permit number], [Facility Name].

SECTION B. General Title V Requirements

#014 [25 Pa. Code § 127.541]

Significant Operating Permit Modifications

When permit modifications during the term of this permit do not qualify as minor permit modifications or administrative amendments, the permittee shall submit an application for significant Title V permit modifications in accordance with 25 Pa. Code § 127.541. Notifications to EPA, pursuant to 25 PA Code §127.522(a), if required, shall be submitted, to the following EPA e-mail box:

R3_Air_Apps_and_Notices@epa.gov

Please place the following in the subject line: TV [permit number], [Facility Name].

#015 [25 Pa. Code §§ 121.1 & 127.462]

Minor Operating Permit Modifications

The permittee may make minor operating permit modifications (as defined in 25 Pa. Code §121.1), on an expedited basis, in accordance with 25 Pa. Code §127.462 (relating to minor operating permit modifications). Notifications to EPA, pursuant to 25 PA Code §127.462(c), if required, shall be submitted, to the following EPA e-mail box:

R3_Air_Apps_and_Notices@epa.gov

Please place the following in the subject line: TV [permit number], [Facility Name].

#016 [25 Pa. Code § 127.450]

Administrative Operating Permit Amendments

(a) The permittee may request administrative operating permit amendments, as defined in 25 Pa. Code §127.450(a). Copies of request for administrative permit amendment to EPA, pursuant to 25 PA Code §127.450(c)(1), if required, shall be submitted to the following EPA e-mail box:

R3_Air_Apps_and_Notices@epa.gov

Please place the following in the subject line: TV [permit number], [Facility Name].

(b) Upon final action by the Department granting a request for an administrative operating permit amendment covered under §127.450(a)(5), the permit shield provisions in 25 Pa. Code § 127.516 (relating to permit shield) shall apply to administrative permit amendments incorporated in this Title V Permit in accordance with §127.450(c), unless precluded by the Clean Air Act or the regulations thereunder.

#017 [25 Pa. Code § 127.512(b)]

Severability Clause

The provisions of this permit are severable, and if any provision of this permit is determined by the Environmental Hearing Board or a court of competent jurisdiction, or US EPA to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

#018 [25 Pa. Code §§ 127.704, 127.705 & 127.707]

Fee Payment

(a) The permittee shall pay fees to the Department in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I (relating to plan approval and operating permit fees). The applicable fees shall be made payable to "The Commonwealth of Pennsylvania Clean Air Fund" with the permit number clearly indicated and submitted to the respective regional office.

(b) Emission Fees. The permittee shall, on or before September 1st of each year, pay applicable annual Title V emission fees for emissions occurring in the previous calendar year as specified in 25 Pa. Code § 127.705. The permittee is not required to pay an emission fee for emissions of more than 4,000 tons of each regulated pollutant emitted from the facility.

(c) As used in this permit condition, the term "regulated pollutant" is defined as a VOC, each pollutant regulated under Sections 111 and 112 of the Clean Air Act and each pollutant for which a National Ambient Air Quality Standard has been promulgated, except that carbon monoxide is excluded.

SECTION B. General Title V Requirements

(d) Late Payment. Late payment of emission fees will subject the permittee to the penalties prescribed in 25 Pa. Code § 127.707 and may result in the suspension or termination of the Title V permit. The permittee shall pay a penalty of fifty percent (50%) of the fee amount, plus interest on the fee amount computed in accordance with 26 U.S.C.A. § 6621(a)(2) from the date the emission fee should have been paid in accordance with the time frame specified in 25 Pa. Code § 127.705(c).

(e) The permittee shall pay an annual operating permit maintenance fee according to the following fee schedule established in 25 Pa. Code § 127.704(d) on or before December 31 of each year for the next calendar year.

(1) Eight thousand dollars ($8,000) for calendar years 2021—2025.

(2) Ten thousand dollars ($10,000) for calendar years 2026—2030.

(3) Twelve thousand five hundred dollars ($12,500) for the calendar years beginning with 2031.

#019 [25 Pa. Code §§ 127.14(b) & 127.449]

Authorization for De Minimis Emission Increases

(a) This permit authorizes de minimis emission increases from a new or existing source in accordance with 25 Pa. Code §§ 127.14 and 127.449 without the need for a plan approval or prior issuance of a permit modification. The permittee shall provide the Department with seven (7) days prior written notice before commencing any de minimis emissions increase that would result from either: (1) a physical change of minor significance under § 127.14(c)(1); or (2) the construction, installation, modification or reactivation of an air contamination source. The written notice shall:

(1) Identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase.

(2) Provide emission rates expressed in tons per year and in terms necessary to establish compliance consistent with any applicable requirement.

The Department may disapprove or condition de minimis emission increases at any time.

(b) Except as provided below in (c) and (d) of this permit condition, the permittee is authorized during the term of this permit to make de minimis emission increases (expressed in tons per year) up to the following amounts without the need for a plan approval or prior issuance of a permit modification:

(1) Four tons of carbon monoxide from a single source during the term of the permit and 20 tons of carbon monoxide at the facility during the term of the permit.

(2) One ton of NOx from a single source during the term of the permit and 5 tons of NOx at the facility during the term of the permit.

(3) One and six-tenths tons of the oxides of sulfur from a single source during the term of the permit and 8.0 tons of oxides of sulfur at the facility during the term of the permit.

(4) Six-tenths of a ton of PM10 from a single source during the term of the permit and 3.0 tons of PM10 at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(5) One ton of VOCs from a single source during the term of the permit and 5.0 tons of VOCs at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(c) In accordance with § 127.14, the permittee may install the following minor sources without the need for a plan approval:

(1) Air conditioning or ventilation systems not designed to remove pollutants generated or released from other sources.

(2) Combustion units rated at 2,500,000 or less Btu per hour of heat input.

SECTION B. General Title V Requirements

(3) Combustion units with a rated capacity of less than 10,000,000 Btu per hour heat input fueled by natural gas supplied by a public utility, liquefied petroleum gas or by commercial fuel oils which are No. 2 or lighter, viscosity less than or equal to 5.82 c St, and which meet the sulfur content requirements of 25 Pa. Code § 123.22 (relating to combustion units). For purposes of this permit, commercial fuel oil shall be virgin oil which has no reprocessed, recycled or waste material added.

(4) Space heaters which heat by direct heat transfer.

(5) Laboratory equipment used exclusively for chemical or physical analysis.

(6) Other sources and classes of sources determined to be of minor significance by the Department.

(d) This permit does not authorize de minimis emission increases if the emissions increase would cause one or more of the following:

(1) Increase the emissions of a pollutant regulated under Section 112 of the Clean Air Act except as authorized in Subparagraphs (b)(4) and (5) of this permit condition.

(2) Subject the facility to the prevention of significant deterioration requirements in 25 Pa. Code Chapter 127, Subchapter D and/or the new source review requirements in Subchapter E.

(3) Violate any applicable requirement of the Air Pollution Control Act, the Clean Air Act, or the regulations promulgated under either of the acts.

(4) Changes which are modifications under any provision of Title I of the Clean Air Act and emission increases which would exceed the allowable emissions level (expressed as a rate of emissions or in terms of total emissions) under the Title V permit.

(e) Unless precluded by the Clean Air Act or the regulations thereunder, the permit shield described in 25 Pa. Code § 127.516 (relating to permit shield) shall extend to the changes made under 25 Pa. Code § 127.449 (relating to de minimis emission increases).

(f) Emissions authorized under this permit condition shall be included in the monitoring, recordkeeping and reporting requirements of this permit.

(g) Except for de minimis emission increases allowed under this permit, 25 Pa. Code § 127.449, or sources and physical changes meeting the requirements of 25 Pa. Code § 127.14, the permittee is prohibited from making physical changes or engaging in activities that are not specifically authorized under this permit without first applying for a plan approval. In accordance with § 127.14(b), a plan approval is not required for the construction, modification, reactivation, or installation of the sources creating the de minimis emissions increase.

(h) The permittee may not meet de minimis emission threshold levels by offsetting emission increases or decreases at the same source.

#020 [25 Pa. Code §§ 127.11a & 127.215]

Reactivation of Sources

(a) The permittee may reactivate a source at the facility that has been out of operation or production for at least one year, but less than or equal to five (5) years, if the source is reactivated in accordance with the requirements of 25 Pa. Code §§ 127.11a and 127.215. The reactivated source will not be considered a new source.

(b) A source which has been out of operation or production for more than five (5) years but less than 10 years may be reactivated and will not be considered a new source if the permittee satisfies the conditions specified in 25 Pa. Code § 127.11a(b).

#021 [25 Pa. Code §§ 121.9 & 127.216]

Circumvention

(a) The owner of this Title V facility, or any other person, may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the

SECTION B. General Title V Requirements

phasing, staging, delaying or engaging in incremental construction, over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.

(b) No person may permit the use of a device, stack height which exceeds good engineering practice stack height, dispersion technique or other technique which, without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants which would otherwise be in violation of this permit, the Air Pollution Control Act or the regulations promulgated thereunder, except that with prior approval of the Department, the device or technique may be used for control of malodors.

#022 [25 Pa. Code §§ 127.402(d) & 127.513(1)]

Submissions

(a) Reports, test data, monitoring data, notifications and requests for renewal of the permit shall be submitted to the:

Regional Air Program Manager
PA Department of Environmental Protection
(At the address given on the permit transmittal letter, or otherwise notified)

(b) Any report or notification for the EPA Administrator or EPA Region III should be addressed to:

Enforcement & Compliance Assurance Division
Air, RCRA and Toxics Branch (3ED21)
Four Penn Center
1600 John F. Kennedy Boulevard
Philadelphia, PA 19103-2852

The Title V compliance certification shall be emailed to EPA at R3_APD_Permits@epa.gov.

(c) An application, form, report or compliance certification submitted pursuant to this permit condition shall contain certification by a responsible official as to truth, accuracy, and completeness as required under 25 Pa. Code § 127.402(d). Unless otherwise required by the Clean Air Act or regulations adopted thereunder, this certification and any other certification required pursuant to this permit shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

#023 [25 Pa. Code §§ 127.441(c) & 127.463(e); Chapter 139; & 114(a)(3), 504(b) of the CAA]

Sampling, Testing and Monitoring Procedures

(a) The permittee shall perform the emissions monitoring and analysis procedures or test methods for applicable requirements of this Title V permit. In addition to the sampling, testing and monitoring procedures specified in this permit, the Permittee shall comply with any additional applicable requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) The sampling, testing and monitoring required under the applicable requirements of this permit, shall be conducted in accordance with the requirements of 25 Pa. Code Chapter 139 unless alternative methodology is required by the Clean Air Act (including §§ 114(a)(3) and 504(b)) and regulations adopted thereunder.

#024 [25 Pa. Code § 127.513]

Compliance Certification

(a) One year after the date of issuance of the Title V permit, and each year thereafter, unless specified elsewhere in the permit, the permittee shall submit to the Department and EPA Region III a certificate of compliance with the terms and conditions in this permit, for the previous year, including the emission limitations, standards or work practices. This certification shall include:

(1) The identification of each term or condition of the permit that is the basis of the certification.
(2) The compliance status.
(3) The methods used for determining the compliance status of the source, currently and over the reporting period.
(4) Whether compliance was continuous or intermittent.

(b) The compliance certification shall be postmarked or hand-delivered no later than thirty days after each anniversary of

SECTION B. General Title V Requirements

the date of issuance of this Title V Operating Permit, or on the submittal date specified elsewhere in the permit, to the Department in accordance with the submission requirements specified in Section B, Condition #022 of this permit. The Title V compliance certification shall be emailed to EPA at R3_APD_Permits@epa.gov.

#025 [25 Pa. Code §§ 127.511 & Chapter 135]

Recordkeeping Requirements

(a) The permittee shall maintain and make available, upon request by the Department, records of required monitoring information that include the following:

(1) The date, place (as defined in the permit) and time of sampling or measurements.

(2) The dates the analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of the analyses.

(6) The operating conditions as existing at the time of sampling or measurement.

(b) The permittee shall retain records of the required monitoring data and supporting information for at least five (5) years from the date of the monitoring sample, measurement, report or application. Supporting information includes the calibration data and maintenance records and original strip-chart recordings for continuous monitoring instrumentation, and copies of reports required by the permit.

(c) The permittee shall maintain and make available to the Department upon request, records including computerized records that may be necessary to comply with the reporting, recordkeeping and emission statement requirements in 25 Pa. Code Chapter 135 (relating to reporting of sources). In accordance with 25 Pa. Code Chapter 135, § 135.5, such records may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions. If direct recordkeeping is not possible or practical, sufficient records shall be kept to provide the needed information by indirect means.

#026 [25 Pa. Code §§ 127.411(d), 127.442, 127.463(e) & 127.511(c)]

Reporting Requirements

(a) The permittee shall comply with the reporting requirements for the applicable requirements specified in this Title V permit. In addition to the reporting requirements specified herein, the permittee shall comply with any additional applicable reporting requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) Pursuant to 25 Pa. Code § 127.511(c), the permittee shall submit reports of required monitoring at least every six (6) months unless otherwise specified in this permit. Instances of deviations (as defined in 25 Pa. Code § 121.1) from permit requirements shall be clearly identified in the reports. The reporting of deviations shall include the probable cause of the deviations and corrective actions or preventative measures taken, except that sources with continuous emission monitoring systems shall report according to the protocol established and approved by the Department for the source. The required reports shall be certified by a responsible official.

(c) Every report submitted to the Department under this permit condition shall comply with the submission procedures specified in Section B, Condition #022(c) of this permit.

(d) Any records, reports or information obtained by the Department or referred to in a public hearing shall be made available to the public by the Department except for such records, reports or information for which the permittee has shown cause that the documents should be considered confidential and protected from disclosure to the public under Section 4013.2 of the Air Pollution Control Act and consistent with Sections 112(d) and 114(c) of the Clean Air Act and 25 Pa. Code § 127.411(d). The permittee may not request a claim of confidentiality for any emissions data generated for the Title V facility.

SECTION B. General Title V Requirements

#027 [25 Pa. Code § 127.3]

Operational Flexibility

The permittee is authorized to make changes within the Title V facility in accordance with the following provisions in 25 Pa. Code Chapter 127 which implement the operational flexibility requirements of Section 502(b)(10) of the Clean Air Act and Section 6.1(i) of the Air Pollution Control Act:

(1) Section 127.14 (relating to exemptions)

(2) Section 127.447 (relating to alternative operating scenarios)

(3) Section 127.448 (relating to emissions trading at facilities with federally enforceable emissions caps)

(4) Section 127.449 (relating to de minimis emission increases)

(5) Section 127.450 (relating to administrative operating permit amendments)

(6) Section 127.462 (relating to minor operating permit amendments)

(7) Subchapter H (relating to general plan approvals and operating permits)

#028 [25 Pa. Code §§ 127.441(d), 127.512(i) and 40 CFR Part 68]

Risk Management

(a) If required by Section 112(r) of the Clean Air Act, the permittee shall develop and implement an accidental release program consistent with requirements of the Clean Air Act, 40 CFR Part 68 (relating to chemical accident prevention provisions) and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act (P.L. 106-40).

(b) The permittee shall prepare and implement a Risk Management Plan (RMP) which meets the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68 and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act when a regulated substance listed in 40 CFR § 68.130 is present in a process in more than the listed threshold quantity at the Title V facility. The permittee shall submit the RMP to the federal Environmental Protection Agency according to the following schedule and requirements:

(1) The permittee shall submit the first RMP to a central point specified by EPA no later than the latest of the following:

(i) Three years after the date on which a regulated substance is first listed under § 68.130; or,
(ii) The date on which a regulated substance is first present above a threshold quantity in a process.

(2) The permittee shall submit any additional relevant information requested by the Department or EPA concerning the RMP and shall make subsequent submissions of RMPs in accordance with 40 CFR § 68.190.

(3) The permittee shall certify that the RMP is accurate and complete in accordance with the requirements of 40 CFR Part 68, including a checklist addressing the required elements of a complete RMP.

(c) As used in this permit condition, the term "process" shall be as defined in 40 CFR § 68.3. The term "process" means any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances or any combination of these activities. For purposes of this definition, any group of vessels that are interconnected, or separate vessels that are located such that a regulated substance could be involved in a potential release, shall be considered a single process.

(d) If the Title V facility is subject to 40 CFR Part 68, as part of the certification required under this permit, the permittee shall:

(1) Submit a compliance schedule for satisfying the requirements of 40 CFR Part 68 by the date specified in 40 CFR § 68.10(a); or,

(2) Certify that the Title V facility is in compliance with all requirements of 40 CFR Part 68 including the registration and submission of the RMP.

SECTION B. General Title V Requirements

(e) If the Title V facility is subject to 40 CFR Part 68, the permittee shall maintain records supporting the implementation of an accidental release program for five (5) years in accordance with 40 CFR § 68.200.

(f) When the Title V facility is subject to the accidental release program requirements of Section 112(r) of the Clean Air Act and 40 CFR Part 68, appropriate enforcement action will be taken by the Department if:

(1) The permittee fails to register and submit the RMP or a revised plan pursuant to 40 CFR Part 68.

(2) The permittee fails to submit a compliance schedule or include a statement in the compliance certification required under Section B, Condition #026 of this permit that the Title V facility is in compliance with the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68, and 25 Pa. Code § 127.512(i).

#029 [25 Pa. Code § 127.512(e)]

Approved Economic Incentives and Emission Trading Programs

No permit revision shall be required under approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this Title V permit.

#030 [25 Pa. Code §§ 127.516, 127.450(d), 127.449(f) & 127.462(g)]

Permit Shield

(a) The permittee's compliance with the conditions of this permit shall be deemed in compliance with applicable requirements (as defined in 25 Pa. Code § 121.1) as of the date of permit issuance if either of the following applies:

(1) The applicable requirements are included and are specifically identified in this permit.

(2) The Department specifically identifies in the permit other requirements that are not applicable to the permitted facility or source.

(b) Nothing in 25 Pa. Code § 127.516 or the Title V permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act, including the authority of the Administrator of the EPA provided thereunder.

(2) The liability of the permittee for a violation of an applicable requirement prior to the time of permit issuance.

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act.

(4) The ability of the EPA to obtain information from the permittee under Section 114 of the Clean Air Act.

(c) Unless precluded by the Clean Air Act or regulations thereunder, final action by the Department incorporating a significant permit modification in this Title V Permit shall be covered by the permit shield at the time that the permit containing the significant modification is issued.

#031 [25 Pa. Code §135.3]

Reporting

(a) The permittee shall submit by March 1 of each year an annual emissions report for the preceding calendar year. The report shall include information for all active previously reported sources, new sources which were first operated during the preceding calendar year, and sources modified during the same period which were not previously reported. All air emissions from the facility should be estimated and reported.

(b) A source owner or operator may request an extension of time from the Department for the filing of an annual emissions report, and the Department may grant the extension for reasonable cause.

#032 [25 Pa. Code §135.4]

Report Format

Emissions reports shall contain sufficient information to enable the Department to complete its emission inventory. Emissions reports shall be made by the source owner or operator in a format specified by the Department.

SECTION C. Site Level Requirements

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.1]

Prohibition of certain fugitive emissions

(a) No person may permit the emission into the outdoor atmosphere of fugitive air contaminant from a source other than the following:

(1) Construction or demolition of buildings or structures.

(2) Grading, paving and maintenance of roads and streets.

(3) Use of roads and streets. Emissions from material in or on trucks, railroad cars and other vehicular equipment are not considered as emissions from use of roads and streets.

(4) Clearing of land.

(5) Stockpiling of materials.

(6) Open burning operations, as specified in 25 Pa. Code § 129.14.

(7) N/A

(8) N/A

(9) Sources and classes of sources other than those identified in (1)-(8) of this condition, for which the permittee has obtained a determination from the Department that fugitive emissions from the source, after appropriate control, meet the following requirements:

(i) The emissions are of minor significance with respect to causing air pollution; and

(ii) The emissions are not preventing or interfering with the attainment or maintenance of any ambient air quality standard.

 # 002 [25 Pa. Code §123.2]

Fugitive particulate matter

A person may not permit fugitive particulate matter to be emitted into the outdoor atmosphere from a source specified in 25 Pa. Code § 123.1(a) (relating to prohibition of certain fugitive emissions) if such emissions are visible at the point the emissions pass outside the person's property.

 # 003 [25 Pa. Code §123.31]

Limitations

A person may not permit the emission into the outdoor atmosphere of any malodorous air contaminants from any source in such a manner that the malodors are detectable outside the property of the person on whose land the source is being operated.

 # 004 [25 Pa. Code §123.41]

Limitations

A person may not permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following:

(a) Equal to or greater than 20% for a period or periods aggregating more than three minutes in any 1 hour.

(b) Equal to or greater than 60% at any time.

 # 005 [25 Pa. Code §123.42]

Exceptions

The opacity limitations as per 25 Pa. Code § 123.41 shall not apply to a visible emission in any of the following instances:

(a) When the presence of uncombined water is the only reason for failure of the emission to meet the limitations.

(b) When the emission results from the operation of equipment used solely to train and test persons in observing the opacity of visible emissions.

(c) When the emission results from the sources specified in 25 Pa. Code § 123.1(a) (relating to prohibition of certain fugitive emissions).

 # 006 [25 Pa. Code §129.14]

Open burning operations

No person may permit the open burning of material in the Southeast Air Basin except where the open burning operations result from:

(a) A fire set to prevent or abate a fire hazard, when approved by the Department and set by or under the supervision of a

SECTION C. Site Level Requirements

public officer.
(b) Any fire set for the purpose of instructing personnel in fire fighting, when approved by the Department.
(c) A fire set for the prevention and control of disease or pests, when approved by the Department.
(d) A fire set in conjunction with the production of agricultural commodities in their unmanufactured state on the premises of the farm operation.
(e) A fire set for the purpose of burning domestic refuse, when the fire is on the premises of a structure occupied solely as a dwelling by two families or less and when the refuse results from the normal occupancy of the structure.
(f) A fire set solely for recreational or ceremonial purposes.
(g) A fire set solely for cooking food.

Fuel Restriction(s).

 # 007 [25 Pa. Code §123.22]

Combustion units

The following applies to all fuel oil used in combustion units (boilers):

(a) A person may not offer for sale, deliver for use, exchange in trade or permit the use of commercial fuel oil in a combustion unit in the Southeast Pennsylvania air basin if the commercial fuel oil contains sulfur in excess of 15 ppm or 0.0015% by weight for No. 2 fuel oil by weight sulfur content, pursuant to 25 Pa. Code § 123.22(e)(2)(i), except as described in 25 Pa. Code § 123.22(e)(2)(ii) and (iii).

(b) Commercial No. 2 fuel oil that was stored in the Commonwealth by the ultimate consumer prior to September 1, 2020 which met the applicable maximum allowable sulfur content for commercial fuel oil through August 31, 2020 in subparagraph (a) at the time it was stored, may be used by the ultimate consumer in this Commonwealth on and after September 1, 2020.

[Compliance with this condition assures compliance with the sulfur emission rate of 1.2/1.0 lb SO2/MMBtu as found in 25 Pa. Code § 123.22(e)(1) for the outer/inner zone, while firing No. 2 fuel oil and the SOx emissions limit of 0.80 lb/MMBtu found in 40 CFR § 60.43.]

II. TESTING REQUIREMENTS.

 # 008 [25 Pa. Code §123.22]

Combustion units

The actual sulfur content of commercial fuel oil shall be determined:

(a) in accordance with the sample collection, test methods and procedures specified under 25 Pa. Code § 139.16 (relating to sulfur in fuel oil); or
(b) by other methods developed or approved by the Department or the Administrator of the EPA, or both.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.512.]

(a) If at any time the Department has cause to believe that air contaminant emissions from any source may be in excess of the limitations specified in this Permit, or established pursuant to, any applicable rule or regulation contained in 25 Pa. Code Article III, the permittee shall be required to conduct whatever tests are deemed necessary by the Department to determine the actual emission rate(s).

(b) Such testing shall be conducted in accordance with the provisions of 25 Pa. Code Chapter 139, the most current version of the DEP Source Testing Manual, and the EPA Clean Air Act National Stack Testing Guidance, when applicable, and in accordance with any restrictions or limitations established by the Department at such time as it notifies the permittee that testing is required.

SECTION C. Site Level Requirements

 # 010 [25 Pa. Code §139.16]

Sulfur in fuel oil.

(a) The following are applicable to tests for the analysis of commercial fuel oil:

(1) The fuel oil sample for chemical analysis shall be collected in a manner that provides a representative sample. Upon the request of a Department official, the person responsible for the operation of the source shall collect the sample employing the procedures and equipment specified in 25 Pa. Code § 139.4(10) (relating to references).

(2) Test methods and procedures for the determination of viscosity shall be that specified in 25 Pa. Code § 139.4(11) (relating to references). The viscosity shall be determined at 100°F.

(3) Tests methods and procedures for the determination of sulfur shall be those specified in 25 Pa. Code § 139.4(12)--(15) and (20).

(4) Results shall be reported in accordance with the units specified in 25 Pa. Code § 123.22 (relating to combustion units).

(b) The testing requirements in subpart (a) above shall be waived in the event that a delivery receipt from the supplier, showing the percentage sulfur in the fuel, is obtained each time a fuel oil delivery is made.

III. MONITORING REQUIREMENTS.

 # 011 [25 Pa. Code §123.43]

Measuring techniques

Visible emissions may be measured using either of the following:

(a) A device approved by the Department and maintained to provide accurate opacity measurements.
(b) Observers, trained and qualified to measure plume opacity with the naked eye or with the aid of any devices approved by the Department.

 # 012 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.511.]

(a) The permittee shall monitor the facility, once per operating day, for the following:

(1) odors which may be objectionable (as per 25 Pa. Code §123.31);
(2) visible emissions (as per 25 Pa. Code §§123.41 and 123.42); and
(3) fugitive particulate matter (as per 25 Pa. Code §§ 123.1 and 123.2).

(b) Objectionable odors, fugitive particulate emissions, and visible emissions that are caused or may be caused by operations at the site shall:

(1) be investigated;
(2) be reported to the facility management, or individual(s) designated by the permittee;
(3) have appropriate corrective action taken (for emissions that originate on-site); and
(4) be recorded in a permanent written log.

(c) After six (6) months of daily monitoring, and upon the permittee's request, the Department will determine the feasibility of decreasing the monitoring frequency to weekly.

(d) After six (6) months of weekly monitoring, and upon the permittee's request, the Department will determine the feasibility of decreasing the frequency of monitoring to monthly.

(e) The Department reserves the right to change the above monitoring requirements at any time, based on but not limited

SECTION C. Site Level Requirements

to: the review of the compliance certification (if applicable), complaints, monitoring results, and/or Department findings.

(f) The daily monitoring of visible emissions, specified in (a), above, shall be waived for those stacks monitored by a Department certified Continuous Opacity Monitoring System (COMs).

IV. RECORDKEEPING REQUIREMENTS.

 # 013 [25 Pa. Code §123.22]

Combustion units

The permittee shall receive with each No. 2 fuel oil delivery an electronic or paper record which legibly and conspicuously contains the following information:

(a) the date of the sale or transfer;
(b) the name and address of the seller;
(c) the name and address of the buyer;
(d) the delivery address;
(e) the volume of commercial fuel oil purchased; and
(f) the identification of the sulfur content of the shipment of fuel oil, determined using the sampling and testing methods specified in the testing requirement above, expressed as one of the following statement: ‘‘The sulfur content of this shipment is 15 ppm or below.’’

 # 014 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall maintain records of all the facility's increases of emissions from the following categories:

(a) emissions increase of minor significance without notification to the Department.
(b) de minimis increases with notification to the Department, via letter.
(c) increases resulting from a Request for Determination (RFD) to the Department.
(d) increases resulting from the issuance of a plan approval and subsequent operating permit.

 # 015 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.511.]

The permittee shall maintain a record of all monitoring of fugitive emissions, visible emissions and odors, including those that deviate from the conditions found in this permit. The record of deviations shall contain, at a minimum, the following items:

(a) Date, time, and location of the incident(s);
(b) The cause of the event; and
(c) The corrective action taken, if necessary, to abate the situation and prevent future occurrences.

For visible emissions monitored by a Department certified Continuous Opacity Monitoring System (COMs) for which the Department's Enforcement Policy-Continuous Emission Monitoring System established penalties for excess emissions the aforementioned recordkeeping requirement will be waived.

V. REPORTING REQUIREMENTS.

 # 016 [25 Pa. Code §123.22]

Combustion units

The permittee shall provide an electronic or written copy of the commercial fuel oil shipment record to the Department upon request, in accordance with 25 Pa. Code § 123.22(g)(4)(ii).

 # 017 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.511(c).]

SECTION C. Site Level Requirements

The permittee shall submit the following:

(a) An annual certificate of compliance, due by April 1st of each year, for the period covering January 1 through December 31 of the previous year. This certificate of compliance shall document compliance with all permit terms and conditions set forth in this Title V permit as required under condition #26 of section B of this permit. The annual certificate of compliance shall be submitted to DEP electronically, and to EPA Region III in electronic form at the following email address: R3_APD_Permits@epa.gov. The subject line shall read: "TVOP No. 23-00017, Constellation Energy Generation LLC/ Eddystone."

(b) A semi-annual deviation report to DEP, due by October 1 of each year, for the period covering January 1 through June 30 of the same year. Note: The annual certification of compliance fulfills the obligation for the second deviation reporting period (July 1 through December 31 of the previous year).

 # 018 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.511.]

(a) The permittee shall report malfunctions, emergencies or incidents of excess emissions to the Department at 484-250-5920. A malfunction is any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. An emergency is any situation arising from sudden and reasonably unforeseeable events beyond the control of the owner or operator of a facility which requires immediate corrective action to restore normal operation and which causes the emission source to exceed emissions, due to unavoidable increases in emissions attributable to the situation. An emergency shall not include situations caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(b) When the malfunction, emergency or incident of excess emissions poses an imminent danger to the public health, safety, welfare, or environment, it shall be reported to the Department and the County Emergency Management Agency by telephone within one (1) hour after the discovery of the malfunction, emergency or incident of excess emissions. The owner or operator shall submit a written or emailed report of instances of such malfunctions, emergencies or incidents of excess emissions to the Department within three (3) business days of the telephone report.

(c) The report shall describe the following:

(1) Name, permit or authorization number, and location of the facility;
(2) Nature and cause of the malfunction, emergency or incident;
(3) Date and time when the malfunction, emergency or incident was first observed;
(4) Expected duration of excess emissions;
(5) Estimated rate of emissions; and
(6) Corrective actions or preventative measures taken.

(d) Any malfunction, emergency or incident of excess emissions that is not subject to the notice requirements of paragraph (b) of this condition shall be reported to the Department by telephone within 24 hours (or by 4:00 PM of the next business day, whichever is later) of discovery and in writing or by e-mail within five (5) business days of discovery. The report shall contain the same information required by paragraph (c), and any permit specific malfunction reporting requirements.

(e) During an emergency an owner or operator may continue to operate the source at their discretion provided they submit justification for continued operation of a source during the emergency and follow all the notification and reporting requirements in accordance with paragraphs (b)-(d), as applicable, including any permit specific malfunction reporting requirements.

(f) Reports regarding malfunctions, emergencies or incidents of excess emissions shall be submitted to the appropriate DEP Regional Office Air Program Manager.

(g) Any emissions resulted from malfunction or emergency are to be reported in the annual emissions inventory report, if the annual emissions inventory report is required by permit or authorization.

SECTION C. Site Level Requirements

 # 019 [25 Pa. Code §135.21]

Emission statements

The permittee shall submit by March 1, of each year, an annual emission statement showing the actual emissions of NOx and VOC emissions for the preceding calendar year. Additionally, a description of the method used to calculate the emissions shall be included. The statement shall contain a certification by a company official or plant manager that the information contained in the statement is true and accurate.

 # 020 [25 Pa. Code §139.16]

Sulfur in fuel oil.

Results of the fuel oil sulfur test shall be reported in accordance with the units specified in 25 Pa. Code § 123.22 (relating to combustion units).

VI. WORK PRACTICE REQUIREMENTS.

 # 021 [25 Pa. Code §123.1]

Prohibition of certain fugitive emissions

A person responsible for any source specified in 25 Pa. Code § 123.1 shall take all reasonable actions to prevent particulate matter from becoming airborne. These actions shall include, but not be limited to, the following:

(a) Use, where possible, of water or suitable chemicals, for control of dust in the demolition of buildings or structures, construction operations, the grading of roads, or the clearing of land.
(b) Application of asphalt, water, or other suitable chemicals, on dirt roads, material stockpiles and other surfaces which may give rise to airborne dusts.
(c) Paving and maintenance of roadways.
(d) Prompt removal of earth or other material from paved streets onto which earth or other material has been transported by trucking or earth moving equipment, erosion by water, or by other means.

 # 022 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.512.]

The permittee shall ensure that the source(s) and air pollution control device(s), listed in this permit, are operated and maintained in a manner consistent with good operating and maintenance practices, and in accordance with manufacturer's specifications.

 # 023 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.512.]

The permittee shall immediately, upon discovery, implement measures which may include the application for the installation of an air cleaning device(s), if necessary, to reduce the air contaminant emissions to within applicable limitations, if at any time the operation of the source(s) identified in this permit, is causing the emission of air contaminants in excess of the limitations specified in, or established pursuant to 25 Pa. Code Article III or any other applicable rule promulgated under the Clean Air Act.

 # 024 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.512.]

The permittee may not modify any air contaminant system identified in this permit, prior to obtaining Department approval, except those modifications authorized by Condition #019(g), of Section B, of this permit.

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

SECTION C. Site Level Requirements

VIII. COMPLIANCE CERTIFICATION.

No additional compliance certifications exist except as provided in other sections of this permit including Section B (relating to Title V General Requirements).

IX. COMPLIANCE SCHEDULE.

No compliance milestones exist.

***** Permit Shield In Effect *****

SECTION D. Source Level Requirements

Source ID: 033 Source Name: BOILER 3

Source Capacity/Throughput:	4,116.000	MMBTU/HR	
	33,352.000	Gal/HR	#2 Oil
	4.480	MMCF/HR	Natural Gas

Conditions for this source occur in the following groups: MAIN BOILERS

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering tangential fired boiler. Installed in 1974, the boiler was orginially designed to accommodate No.6, crude, and waste oil with a 4116 MMBtu/hr input. The boiler was modified in 1994 to operate on No. 2 oil and natural gas. Originally equipped with ESP for crude oil use, the EPS were not ever used since crude oil was never used in the boiler. Currently, the boiler operates only on No. 2 oil and natural gas.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 034 Source Name: AUXILIARY BOILER A

Source Capacity/Throughput:	124.000	MMBTU/HR	
	925.900	Gal/HR	#2 Oil
	122.300	MCF/HR	Natural Gas

Conditions for this source occur in the following groups: AUX BOILERS

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering 124 MMBtu/hr package type boiler capable of burning natural gas and No. 2 fuel oil and is used for steam only. Unit was installed in 1973 but the burner was upgraded in 1994 to a low NOx burner.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 035 Source Name: AUXILIARY BOILER B

Source Capacity/Throughput:	124.000	MMBTU/HR	
	925.900	Gal/HR	#2 Oil
	122.300	MCF/HR	Natural Gas

Conditions for this source occur in the following groups: AUX BOILERS

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering 124 MMBtu/hr package type boiler capable of burning natural gas and No. 2 fuel oil and is used for steam only. Unit was installed in 1973 but the burner was upgraded in 1994 to a low NOx burner.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 036 Source Name: AUXILIARY BOILER C

Source Capacity/Throughput:	124.000	MMBTU/HR	
	925.900	Gal/HR	#2 Oil
	122.300	MCF/HR	Natural Gas

Conditions for this source occur in the following groups: AUX BOILERS

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering 124 MMBtu/hr package type boiler capable of burning natural gas and No. 2 fuel oil and is used for steam only. Unit was installed in 1973 but the burner was upgraded in 1994 to a low NOx burner.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 041 Source Name: BOILER 4

Source Capacity/Throughput:	4,116.000	MMBTU/HR	
	33,352.000	Gal/HR	#2 Oil
	4.480	MMCF/HR	Natural Gas

Conditions for this source occur in the following groups: MAIN BOILERS

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering tangential fired boiler. Installed in 1974, the boiler was orginially designed to accommodate No.6, crude, and waste oil with a 4116 MMBtu/hr input. The boiler was modified in 1994 to operate on No. 2 oil and natural gas. Originally equipped with ESP for crude oil use, the EPS were not ever used since crude oil was never used in the boiler. Currently, the boiler operates only on No. 2 oil and natural gas.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 037 Source Name: NO. 10 COMBUSTION TURBINE

Source Capacity/Throughput:	1,726.000	Gal/HR	Kerosene
	1,726.000	Gal/HR	#2 Oil

Conditions for this source occur in the following groups: TURBINES

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The source consists of a 233 MMBtu/hr Pratt and Whitney FT4-8 diesel /kerosene fueled turbine installed in 1967 that powers a 18 MW generator.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 038 Source Name: NO. 20 COMBUSTION TURBINE

Source Capacity/Throughput:	1,726.000	Gal/HR	Kerosene
	1,726.000	Gal/HR	#2 Oil

Conditions for this source occur in the following groups: TURBINES

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The source consists of a 233 MMBtu/hr Pratt and Whitney FT4-8 diesel /kerosene fueled turbine installed in 1967 that powers a 18 MW generator.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 039 Source Name: NO. 30 COMBUSTION TURBINE

Source Capacity/Throughput:	2,104.000	Gal/HR	Kerosene
	2,104.000	Gal/HR	#2 Oil

Conditions for this source occur in the following groups: TURBINES

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The source consists of a 284 MMBtu/hr Pratt and Whitney FT4-9 diesel /kerosene fueled turbine installed in 1970 that powers a 20 MW generator.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 040 Source Name: NO. 40 COMBUSTION TURBINE

Source Capacity/Throughput:	2,104.000	Gal/HR	Kerosene
	2,104.000	Gal/HR	#2 Oil

Conditions for this source occur in the following groups: TURBINES

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The source consists of a 284 MMBtu/hr Pratt and Whitney FT4-9 diesel /kerosene fueled turbine installed in 1970 that powers a 20 MW generator.

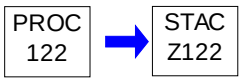
***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 122 Source Name: #2 OIL STORAGE TANK (1.05 MMGAL)

Source Capacity/Throughput:

Conditions for this source occur in the following groups: OIL STORAGE



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 123 Source Name: FUEL OIL STORAGE TANKS(2)

Source Capacity/Throughput:

Conditions for this source occur in the following groups: OIL STORAGE

PROC 123 → STAC Z123

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.503]

Application information.

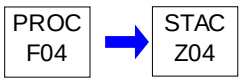
This source consists of two (2) 8.4 million gallon fixed roof storage tanks used to store fuel oil.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: F04 Source Name: OIL DELIVERY FUGITIVES

Source Capacity/Throughput:



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Good operating practices shall be followed to minimize fugitive emissions.

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

***** Permit Shield in Effect. *****

SECTION E. Source Group Restrictions.

Group Name: AUX BOILERS

Group Description: Auxilary Boilers 124 MMBtu

Sources included in this group

ID	Name
034	AUXILIARY BOILER A
035	AUXILIARY BOILER B
036	AUXILIARY BOILER C

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

A person may not permit the emission into the outdoor atmosphere of particulate matter from this boiler in excess of 0.24 lbs/MMBtu of heat input, pursuant to 25 Pa. Code § 123.11(a)(2).

 # 002 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.112(g)(1)(i)-(ii).]

NOx emissions from each boiler in this group shall not exceed any of the following as a daily average:

(1) 0.10 lb NOx/MMBtu heat input when firing natural gas.
(2) 0.12 lb NOx/MMBtu heat input when firing No. 2 fuel oil

[Compliance with the above RACT III NOx emission standards assure compliance with the RACT I NOx emission standards according to 25 Pa. Code §129.91- NOx emissions from this boiler shall not exceed 0.14 lbs/MMBtu. and 129.97(i) and the RACT II NOx emission standards according to 25 Pa. Code §§ 129.97(g)(1)(i) - (ii).]

(b) The permittee shall conduct monitoring and testing in accordance with a Department-approved emissions source test that meets the requirements of Chapter 139, Subchapter A (relating to sampling and testing methods and procedures). The source test shall be conducted one time in each 5-year calendar period.

 # 003 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.91 and 129.112.]

NOx emissions from each boiler in this group shall not exceed 36.0 tons in any 12 consecutive month period.

 # 004 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7500]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What emission limits, work practice standards, and operating limits must I meet?

[Additional authority for this permit conditions is also derived from Table 2 of this subpart, 40 CFR § 63.7510(e), and 25 Pa. Code § 127.441.]

When burning fuel oil, emissions to the atmosphere shall not exceed the following, except for start-up and shut-down:
(a) HCl - 1.1E-03 lbs/MMBtu of heat input or 1.4E-03 lb per MMBtu of steam output;
(b) Hg - 7.3E-07 lb per MMBtu of heat input or 8.8E-07 lb per MMBtu of steam output;
(c) CO - 130 ppm by volume on a dry basis corrected to 3 percent oxygen or 0.13 lb per MMBtu of steam output; and
(d) PM emissions:
(1) filterable PM - 7.9E-03 lb per MMBtu of heat input or 9.6E-03 lb per MMBtu of steam output; or
(2) the permittee may choose to limit the emissions Total Select Metals (TSM) to 6.2E-05 lb per MMBtu of heat input or

SECTION E. Source Group Restrictions.

7.5E-05 lb per MMBtu of steam output.

Fuel Restriction(s).

 # 005 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Only No. 2 fuel oil and/or natural gas shall be burned in these auxiliary boilers.

Throughput Restriction(s).

 # 006 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The heat throughput for each auxiliary boiler shall not exceed 657,000 MMBtu, or an annual capacity factor of 60%, in any 12 consecutive month period. Heat input shall be determined by a Department approved method.

II. TESTING REQUIREMENTS.

 # 007 [25 Pa. Code §127.512]

Operating permit terms and conditions.

(a) The permittee shall perform stack tests on boilers in this group according to the following:

(i) For compliance with NOx limits under 25 Pa Code § 129.115(b)(6):

(1) One boiler shall be tested every five (5) years, where five (5) calendar years is defined as beginning with the calendar year the latest stack test was performed and ending on December 31, five (5) years later.

(2) No one boiler shall be tested repeatedly for each consecutive five (5) year period. The permittee must alternate between boilers for stack tests.

(3) Each boiler must be tested at least once in the 15-year period (three 5-year periods).

(4) If the permittee fails to comply with requirements of the above schedule; modifies the boilers or changes their operation in a manner that would increase emissions; or does not comply with the maintenance requirements in Condition #021 of this Group and Section, all boilers will need to be tested in the same 5- year period. The permittee may request a return to the alternating schedule above once any deficiencies listed in this paragraph have been addressed, all boilers have been tested during one five(5) year interval and the tests have been found acceptable.

(ii) For compliance with Hg, HCl, CO and filterable PM or total suspended metals (TSM) testing shall be performed as follows:

(1) Perform annual stack test for each contaminant. Tests must be completed no more than 13 months after the previous test unless the boiler is eligible for the reduced testing listed in Paragraph (a)(ii)(2) of this Condition. In lieu of testing for Hg, HCl and TSM only, the permittee may use fuel analysis for liquid fuel only to comply with limits as allowed under 40 CFR § 63.7505(a). For gaseous fuels, fuel testing for Hg is permitted in lieu of stack testing. Fuel testing must be performed according to requirements of 40 CFR §§ 63.7515, 63.7521, 63.7530, and Table 6 of 40 CFR Part 63 Subpart DDDDD.

(2) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit for the pollutant, and if there are no changes in the operation of the individual boiler that could increase emissions, the permittee may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test.

(3) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit for a pollutant, the permittee must conduct annual performance tests for that pollutant until all performance tests over a

SECTION E. Source Group Restrictions.

consecutive 2-year period meet the required level (at or below 75 percent of the emission limit).

(4) Under 40 CFR § 63.7515(h), if the boilers are designed to burn light distillate oil (diesel, No. fuel oil, biodiesel), the fuel used by the boilers is ultra-low sulfur (15 ppm sulfur or lower), and the pollutants measured during the initial compliance performance tests meet the emission limits in Table 2 of 40 CFR Part 63 Subpart DDDDD, the facility does not need to conduct further performance tests (stack tests). The facility must demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel and amount combusted on a monthly basis. The facility shall keep a copy of the initial compliance test results at the facility for review and verification. If the facility intends to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, the facility must conduct new performance tests within 60 days of burning the new fuel type.

(5) If fuel testing is being used in lieu of stack testing and the boilers share a common fuel supply, sampling from the common supply is acceptable for compliance for all boilers sharing the supply.

(b) In accordance with 25 Pa. Code § 139.11(1), performance tests shall be conducted while the source is operating at maximum routine operating conditions or under such other conditions, within the capacity of the equipment, as may be requested by the Department. When testing of a source is required on a recurring basis, a single procedural protocol may be submitted for approval; thereafter, a letter referencing the previously approved procedural protocol is sufficient. However, if modifications are made to the process(es), if a different stack testing company is used, or if an applicable section of the stack testing manual has been revised since approval, a new protocol must be submitted for approval. Refer to PADEP Source Testing Program website online for further information related to source testing including Source Testing FAQ and the PADEP Source Testing Manual.

(c) The stack test shall, at a minimum, test for the following according to listed regulations:

(i) NOx – testing shall be conducted according to the requirements in 25 Pa Code § 129.115(b)(6)
(ii) Hg, HCl, CO and filterable PM or TSM – testing shall be performed according to requirements of 40 CFR § 63.7505 and 40 CFR Part 63 Subpart DDDDD Table 5.

(d) Tests shall also be conducted in accordance with the provisions of the current version of the DEP Source Testing Manual, the methods found in the 40 CFR Part 60 Appendices and the EPA Clean Air Act National Stack Testing Guidance.

(e) At least ninety (90) days prior to the test, the permittee shall submit to the Department for approval the procedures for the test and a sketch with dimensions indicating the location of sampling ports and other data to ensure the collection of representative samples.

(f) At least thirty (30) days prior to the test, the Regional Air Quality Manager, shall be informed of the date and time of the test.

(g) Within sixty (60) days after the source test(s), an electronic copy of the complete test report, including all operating conditions, shall be submitted to the Regional Air Quality Manager for approval.

(h) In the event that any of the above deadlines cannot be met, the permittee may request an extension for the due date(s) in writing and include a justification for the extension. The Department may grant an extension for a reasonable cause.

 # 008 [25 Pa. Code §127.512]

Operating permit terms and conditions.

(a) The permittee shall email all source test submissions (notifications, protocols, reports, supplemental information, etc.) to both the AQ Program Manager for the Southeast Regional Office and the PSIMS Administrator in Central Office (email addresses are provided below). Any questions or concerns about source testing submissions can be sent to RA-EPstacktesting@pa.gov and the PSIMS Administrator will address them.

Southeast Region
RA-EPSEstacktesting@pa.gov

SECTION E. Source Group Restrictions.

Central Office
RA-EPstacktesting@pa.gov

(b) The following pertinent information shall be listed on the title page.

1. Test Date(s)

a. For protocols, provide the proposed date on which testing will commence or "TBD"
b. For reports, provide the first and last day of testing

2. Facility Identification Number (Facility - ID): For test programs that were conducted under a multi-site protocol, also include the PF ID under which the protocol was stored in PSIMS, as indicated in the protocol response letter.

3. Source ID(s) for the applicable source(s) and air pollution control device(s): The term Source ID is used in the permit but "Other Id" is used in DEP electronic systems. They are the same number and must also be listed for control equipment

4. Testing Requirements:

(i). Operating permit number 23-00017
(ii) 40 CFR Part 63 Subpart DDDDD (when testing for Hg, HCl, CO or filterable PM/TSM)
(iii) RACT III Compliance under 25 Pa Code § 129.112(g)(1)(i)-(ii)

(c) If confidential information must be submitted, submit both a public copy, which has been redacted, and a confidential copy. The cover page of each submittal should state whether it is a "Public Copy" or "Confidential Copy" and each page of the latter must be marked "CONFIDENTIAL".

 # 009 [25 Pa. Code §127.512]

Operating permit terms and conditions.

For fuel testing used in lieu of stack testing, the facility may use fuel analysis provided by the supplier if the following are met:

(a) The testing is done in accordance with the requirements for each pollutant in Table 6 of 40 CFR Part 63 Subpart DDDDD, 40 CFR §§ 63.7510 and 63.7521.
(b) The permittee shall maintain records of the result of testing performed provided by the supplier. The records shall list the supplier, fuel tested, the date of testing, test method used for each pollutant, and results in units prescribed for limits from Subcategories 14 and 16 of Table 2 of 40 CFR Part 63 Subpart DDDDD.

(c) Fuel analysis must be performed monthly for each type of fuel burned. The permittee may comply with this monthly requirement by having the supplier comply with the sampling interval found in 40 CFR § 63.7515(e). If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, the permittee may decrease the fuel analysis frequency for the supplier to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or the boiler begins burning a new type of fuel, the permittee must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

 # 010 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7515]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

When must I conduct subsequent performance tests or fuel analyses, or tune-ups?

[Additional authority for this permit condition is derived from 25 Pa. Code § 127.441.]

For units that burn light liquid fuel as described in 40 CFR 63, Subpart DDDDD, the permittee shall demonstrate compliance status for the following:
(1) Hg and HCl emissions: by conducting a performance test or fuel analysis
(2) PM (TSM) emissions: by conducting a performance test
(3) CO emissions: by conducting a performance test

SECTION E. Source Group Restrictions.

If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit for the pollutant, and if there are no changes in the operation of the individual boiler that could increase emissions, the permittee may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test.

If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit for a pollutant, the permittee must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit).

Results of the performance test shall be submitted to the Department within sixty (60) days after completion of the test.

III. MONITORING REQUIREMENTS.

 # 011 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The following shall be monitored on a daily basis for each boiler when operating:

(a) fuel consumed, by type and amount;
(b) steam output; and
(c) hours of operation.

IV. RECORDKEEPING REQUIREMENTS.

 # 012 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Records, and sufficient calculations, shall be maintained to document compliance with each limit for these sources. The data shall be recorded and maintained in a time frame consistent with the averaging period.

 # 013 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The following fuel oil characteristics shall be verified and recorded on a monthly, and an as-delivered, basis:

(a) sulfur content percent, by weight; and
(b) heat content, in MMBtu/gal.

 # 014 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The following daily records for these boilers shall be kept:

(a) fuel consumed, by type and amount;
(b) steam output; and
(c) hours of operation.

Calculations shall be performed monthly, to demonstrate compliance with the 12 consecutive month heat throughput limit, or capacity factor for these auxiliary boilers.

 # 015 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority form 40 CFR § 63.7540(a)(10)(vi).]

(a)The permittee shall keep maintenace reports for maintenance required under Condition #022 of this Group and Section containing the following information on site and available:

(1) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler;

(2) A description of any corrective actions taken as a part of the tune-up; and

SECTION E. Source Group Restrictions.

(3) The type and amount of fuel used over the 12 months prior to the tune-up. Units sharing a fuel meter may estimate the fuel used by each unit.

(b) Records shall be maintained for at least 5 years.

 # 016 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7555]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What records must I keep?

[Additional authority for this permit condition is also derived from 25 Pa. Code 127.441.]

The permittee shall retain the following records:
(a) a copy of each notification and report submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted, according to the requirements in 40 CFR § 63.10(b)(2)(xiv); and
(b) records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 CFR § 63.10(b)(2)(viii).

 # 017 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7555]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What records must I keep?

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.441.]

For each boiler, you must also keep the following records:
(a) monthly records of fuel use and type for each boiler;
(b) for units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler was operating;
(c) a copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of 40 CFR § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing;
(d) a copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of 40 CFR § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing;
(e) if, consistent with 40 CFR § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than seventy-five (75) percent of the applicable emission limit, and document that there was no change in source operations including fuel composition that would cause emissions of the relevant pollutant to increase within the past year;
(f) records of the occurrence and duration of each malfunction of the boiler;
(g) records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in 40 CFR § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler to its normal or usual manner of operation;
(h) records of the calendar date, time, occurrence and duration of each startup and shutdown; and
(i) records of the type(s) and amount(s) of fuels used during each startup and shutdown.

V. REPORTING REQUIREMENTS.

 # 018 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7550]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What reports must I submit and when?

[Additional authority for this permit condition is also derived from 25 Pa.Code § 127.441.]

The permittee shall submit compliance reports according to the following schedule:

Initial report covering the period between January 31, 2016 and June 30, 2016.

Subsequent reports shall cover the periods from July 1 through December 30 and from January 1 through June 30.

SECTION E. Source Group Restrictions.

All reports shall be post marked (or electronically delivered) to the Department and the EPA no later than July 31 (for the period ending June 30) and January 31 (for the period ending December 31).

The compliance report shall contain the following information:
(a) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the following information:
(1) company and Facility name and address;
(2) process unit information, emissions limitations, and operating parameter limitations;
(3) date of report and beginning and ending dates of the reporting period;
(4) the total operating time during the reporting period; and
(5) include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.
(b) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the following information:
(1) company and Facility name and address;
(2) process unit information, emissions limitations, and operating parameter limitations;
(3) date of report and beginning and ending dates of the reporting period;
(4) the total operating time during the reporting period;
(5) the total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure;
(6) if you are conducting performance tests once every three (3) years consistent with 40 CFR § 63.7515(b) or (c), the date of the last two (2) performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions;
(7) if there are no deviations from any emission limits or operating limits, a statement that there were no deviations from the emission limits or operating limits during the reporting period;
(8) if a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken during a malfunction of the boiler to minimize emissions in accordance with 40 CFR § 63.7500(a)(3), including actions taken to correct the malfunction;
(9) if you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in 40 CFR § 63.7545(e)(5)(i); and
(10) for each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in (i) through (iii), below.
(i) a description of the deviation and which emission limit or operating limit from which you deviated;
(ii) information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken; and
(iii) if the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

VI. WORK PRACTICE REQUIREMENTS.

 # 019 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Fuel oil analysis, or fuel samples shall be provided to the Department, upon request.

 # 020 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.91, 129.97 and 129.112 .]

NOx emissions from these boilers shall be controlled with Low-NOx burners.

SECTION E. Source Group Restrictions.

 # 021 [25 Pa. Code §127.512]

Operating permit terms and conditions.

These boilers shall be maintained in accordance with requirements of 40 CFR § 63.7540(a)(10). Each boiler shall have an annual tune-up including the following items:

(a) Inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown but not to exceed 36 months from previous inspection) At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(b) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(c) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown but not to exceed 36 months from previous inspection);

(d) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown but not to exceed 36 months from previous inspection);

(e) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOX requirement to which the unit is subject; and

(f) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

 # 022 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7525]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What are my monitoring, installation, operation, and maintenance requirements?

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.441.]

The permittee shall install, operate, calibrate, and maintain the oxygen analyzer systems in accordance with the manufacturer's specifications.

 # 023 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7530]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

[Additional authority for this permit condition is derived from 40 CFR 63, Subpart DDDDD, Table 4, and 25 Pa. Code § 127.441.]

The permittee shall maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.

The permittee shall maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test.

VII. ADDITIONAL REQUIREMENTS.

 # 024 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7500]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial

SECTION E. Source Group Restrictions.

and Institutional Boilers and Process Heaters.

What emission limits, work practice standards, and operating limits must I meet?

The one time energey assessment for these boilers was completed on Septmember 18, 2015 to satisfy the requirements of 40 CFR § 63.7510(e).

***** Permit Shield in Effect. *****

SECTION E. Source Group Restrictions.

Group Name: MAIN BOILERS

Group Description: Large EGU Boilers 4116 MMBtu

Sources included in this group

ID	Name
033	BOILER 3
041	BOILER 4

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

A person may not permit the emission into the outdoor atmosphere of particulate matter from the stack associated with this boiler in excess of 0.1 lbs/MMBtu of heat input, pursuant to 25 Pa. Code § 123.11(a)(3).

 # 002 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.112(g)(1)(i)-(ii).]

NOx emissions from each boiler in this group shall not exceed any of the following as a daily average:

(1) 0.10 lb NOx/MMBtu heat input when firing natural gas.
(2) 0.12 lb NOx/MMBtu heat input when firing No. 2 fuel oil

When co-firing fuels, the emissions shall be prorated, as described in 40 CFR § 60.44(b), from the above emission limits and the percent heat input for each fuel fired in lb/MMBtu.

[Compliance with the above RACT III NOx emission standards assure compliance with the RACT I NOx emission standards (Condition #002(a) under this source), according to 25 Pa. Code §§ 129.97(a)(1) and 129.97(i); the RACT II NOx emission standards according to 25 Pa. Code §§ 129.97(g)(1)(i) - (ii); and the NOx emissions standards of 40 CFR § 60.44(a)(1)-(2). Additionally, these RACT III limits supersede the limits and requirements under 25 Pa Code §§ 129.201-205.]

 # 003 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 129.91.]

NOx emissions from the combined stack, which includes Boilers 3 and 4, shall not exceed any of the following, whichever is more stringent:

(a) 0.29 lbs/MMBtu of heat input as a 30-operating day average;

(1) an operating day is a 24-hour period between midnight and the following midnight during which any fuel is combusted in the steam-generating unit for at least one operating hour;
(2) an operating hour is a clock hour in which any fuel is combusted in the steam-generating unit for at least 45 minutes; and
(3) compliance shall be determined each operating day by calculating the arithmetic average of all hourly emission rates for 30 consecutive operating days, inclusive of the current operating day.

(b) 5568 tons in any 12 consecutive month period.

[Compliance with Section E, Condition #002 which contains RACT III requirements under 25 Pa Code § 129.112 for this source group ensures compliance with this condition.]

SECTION E. Source Group Restrictions.

 # 004 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.91 and 129.114]

The aggregated VOC emissions from the boilers in this group shall not exceed 0.002 lbs/MMBtu, and 35.9 tons in any 12 consecutive month period, whichever is more stringent.

Fuel Restriction(s).

 # 005 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Only #2 fuel oil and/or natural gas shall be burned in these boilers.

Throughput Restriction(s).

 # 006 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The annual heat input for each boiler in the group shall not exceed 17,186,207 MMBtu of heat input as a 12-month rolling aggregate calculated monthly.

 # 007 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority from 40 CFR § 63 Subpart UUUUU]

These boilers meet the definition of limited-use liquid oil-fired units from 40 CFR § 63.10042 by remaining below an annual capacity factor of less than 8% of the nameplate heat input capacity (36,056,160 MMBtu/yr total capacity) when burning when burning No. 2 oil. If the annual heat input to a boiler from No.2 fuel oil exceed 2,884,493 MMBtu annually, that boiler will be subject to the full requirements of 40 CFR Part 63 Subpart UUUUU for continental liquid oil-fired units.

II. TESTING REQUIREMENTS.

 # 008 [25 Pa. Code §127.512]

Operating permit terms and conditions.

A Relative Accuracy Test Audit (RATA) shall be conducted on each CEMs to demonstrate compliance with the performance specifications of the Department's "Continuous Source Monitoring Manual".

III. MONITORING REQUIREMENTS.

 # 009 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Fuel throughput and type, and hours of operation, shall be monitored on a daily basis for each boiler.

 # 010 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Fuel oil sulfur percent content (by weight) and heat content (MMBtu/gal) shall be verified and recorded, in the time-frames prescribed by this permit, for this source.

IV. RECORDKEEPING REQUIREMENTS.

 # 011 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Records, and sufficient calculations, shall be maintained to document compliance with each emission limit for these sources. The data shall be recorded and maintained in a time frame consistent with the averaging period.

 # 012 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Fuel throughput and type, and hours of operation, shall be recorded on a daily basis for each boiler.

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 # 013 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The NOx emission tracking system shall record, at a minimum, the following information:

(a) heat input (MMBtu/hr) on an hourly basis for each boiler;
(b) hours of operation for each boiler; and
(c) flue flow and flue gas contaminants concentration.

 # 014 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Records of tune-ups perform on each boiler for compliance with 40 CFR Part 63 Subpart UUUUU must be keep onsite documenting the work performed during tune-ups, the pre- and post- CO and NOX concentrations in the exhaust stream, any correction actions taken due to tune-ups, and the types and amounts of fuel use in the 12 months preceding each tune-up.

 # 015 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.100 and 129.115(b)(4).]

The owner or operator shall demonstrate compliance with the emission limitations under Conditions #001 and 002, for these sources, by operating a CEMS for NOx, in accordance with the following procedures:

(1) Compliance shall be demonstrated using a daily average for RACT III in Condition #001:

(i) The daily average shall be calculated by summing the total pounds of pollutant emitted for the calendar day and dividing that value by the total heat input to the source for the same calendar day for each boiler.

(ii) The daily average for the source shall include all emissions that occur during the entire day, including startup, shutdown and malfunction.

[Compliance with the RACT III requirements ensure compiance with RACT II under 25 Pa Code § 129.100]

 # 016 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.97,129.100, 129.112 and 129.115]

(a) The permittee shall record data and perform sufficient calculations to demonstrate compliance with each of the emission limits for these sources.

(b) The records shall be retained for 5 years and made available to the Department or appropriate approved local air pollution control agency upon receipt of a written request from the Department or appropriate approved local air pollution control agency.

V. REPORTING REQUIREMENTS.

 # 017 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR 63, Subpart UUUUU.]

Recordkeeping and reporting requirements shall follow those set forth in the general requirements found in 40 CFR §§ 63.9 and 10 as well as those found in 40 CFR § 63.10031.

 # 018 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority from 40 CFR § 63.10031.]

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Tune-ups must be reported in the quarterly compliance report of the quarter in which it took place. Tune-up date is the date on which the requirements of the tune-up under 63.10021(e) have been completed.

VI. WORK PRACTICE REQUIREMENTS.

 # 019 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The permittee shall use the methods provided in 40 CFR 75.31-33 for NOx emissions and 40 CFR 75 Appendix D for fuel flow to supplement any data not captured by the continuous monitors required for these source. The CEMS, along with any missing data determined under this condition, shall be used to determine compliance with the NOx emission limits for this source.

 # 020 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Continuous Monitors shall be operated and maintained in accordance with the latest applicable version of the Department's "Continuous Source Monitoring Manual", for CO2, NOx, Opacity and fuel flow.

 # 021 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The continuous monitoring system for CO2, opacity, and NOx shall be operated and maintained to achieve the following data availability requirements:

(1) At least 95% valid hours/calendar quarter, or at least 90% valid hours/calendar month, where a valid hour is as defined in the current revision of the Continuous Source Monitoring Manual.

(2) The permittee shall use the method provided in 40 CFR Section 75.31-33 for NOx emissions and 40 CFR 75 Appendix D for fuel flow to supplement any data not captured by the CEMS required for these sources. The CEMS, along with any missing data determined under this condition will be used to determine compliance with the NOx emission limits for these sources.

 # 022 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The NOx analyzer, and Department approved Data Acquisition System, shall quantify emissions in lbs NOx/MMBtu heat input to demonstrate compliance with the NOx emission limit for these sources.

 # 023 [25 Pa. Code §127.512]

Operating permit terms and conditions.

NOx emissions from these boilers shall be controlled by a separate over-fire air (SOFA) system to reduce NOx emissions.

 # 024 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The NOx and fuel flow continuous monitors shall be certified by the Department. The resulting total output of the common stack shall be reported in pounds of NOx per hour. The methods to quantify NOx emissions from the common stack and each individual unit shall be approved by the Department, with the resulting output in lbs/MMBtu.

 # 025 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR 63, Subpart UUUUU, Table 3.]

The permittee shall conduct a tune-up on each boiler's EGU burners and combustion controls no more than thirty-six (36) calendar months after the previous tune-up. Tune-up shall include the following as applicable:

(1) Inspection needs to include inspection of the flame pattern and adjustment according to manufacturer specs or best combustion engineering practices.

(2) Inspect the windbox pressures and air proportions and adjust as needed. Repair any dampers, actuators, controls and sensors as needed.

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(3) Optimize combustion to minimize generation of NOx and CO according to manufacturer's spec or best combustion engineering practices.

(4) Measure the concentration of NOx and CO under full load or predominant operating load before and after the tune-up. If using a neural network optimization system only one pre- and post-tune up measurement is required rather than continuous monitoring.

(5) For repairs: If special parts are needed that impact control of NOx and CO, they must be installed within 3 calendar months after the inspection. Parts not impacting NOx and CO may be installed according to operator's schedule.

 # 026 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this condition from 40 CFR § 72.9(b)]

(a) The permittee shall operate and maintain a CEM system for SO2 in compliance with 40 CFR Part 75 standards.

(b) The permittee may calculate SO2 emissions in accordance with Appendix D to 40 CFR Part 75 when natural gas or No. 2 fuel oil is used as fuel.

 # 027 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.97,129.100 and 129.115]

(a) The permittee shall record data and perform sufficient calculations to demonstrate compliance with each of the emission limits for these sources.

(b) The records shall be retained for 5 years and made available to the Department or appropriate approved local air pollution control agency upon receipt of a written request from the Department or appropriate approved local air pollution control agency.

VII. ADDITIONAL REQUIREMENTS.

 # 028 [25 Pa. Code §127.11a]

Reactivation of sources.

(a) If any of these sources are out of operation for one (1) year or more and less than five (5) years without submission to the Department of a maintenance plan as described in 25 PA Code § 127.11a(a)(1), a plan approval will be required to reactivate the source. Sources out of operation for one (1) year or more and less than five (5) years with an implemented maintenance plan will require a reactivation plan submitted to the Department at least 60 days prior to reactivation date.

(b) If any of these sources are out of operation for at least five (5) years but less than 10 years without the submissions to the Department of a maintenance plan as described in 25 PA Code § 127.11a(a)(1), the source will be considered a new source and subject the requirements applicable to new sources. Sources out of operation for at least five (5) years but less than 10 years with an implemented maintenance plan will not be considered new sources. A plan approval is required to reactivate a source that is out of operation for more than 5 years.

 # 029 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Compliance with the initial tune-up, as required under 40 CFR § 63.10005(f) and due no later October 13, 2015, was demonstrated 6/23/2015 for Boiler 3 (Source ID 033) and 6/24/2015 for Boiler 4 (Source ID 041).

 # 030 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[40 C.F.R. § 52.2040 and 40 C.F.R. §52.2041 (relating to interstate pollutant transport provisions)]

(a) The owner and operator of each NOx or SO2 source located within the State of Pennsylvania and for which requirements are set forth under the Federal CSAPR in 40 C.F.R. Part 97 must comply with such applicable requirements. The obligation to comply with these requirements in Part 97 will be eliminated by the promulgation of an approval by the EPA's Administrator of a revision to the Pennsylvania State Implementation Plan (SIP) as meeting the requirements of CSAPR,

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except to the extent the EPA Administrator's approval is partial or conditional or unless such approval is under 40 C.F.R. § 51.123 or under 40 C.F.R. § 51.124. Upon the approval of Pennsylvania's State Implementation Plan, the owner and operator shall comply with 25 Pa. Code §§ 145.8 through 145.223.

(b) Notwithstanding any provisions 40 C.F.R. § 52.2040, if, at the time of such approval of the State's SIP, the EPA's Administrator has already allocated CSAPR NOx Ozone Season allowances to sources in the State for any years, the provisions of 40 C.F.R. Part 97 authorizing the Administrator to complete the allocation of CSAPR NOx Ozone Season allowances for those years shall continue to apply, unless the Administrator approves a SIP provision that provides for the allocation of the remaining CSAPR NOx Ozone Season allowances for those years.

 # 031 [25 Pa. Code §127.512]

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[Transport Rule (TR) SO2 Group 1 Trading Program requirements (40 CFR § 97.606)]

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.630 through 97.635.

(2) The emissions data determined in accordance with §§ 97.630 through 97.635 shall be used to calculate allocations of
TR SO2 Group 1 allowances under §§ 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO2 Group 1 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO2 emissions requirements.

(1) TR SO2 Group 1 emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO2 Group 1 allowances available for deduction for such control period under § 97.624(a) in an amount not less than the tons of total SO2 emissions for such control period from all TR SO2 Group 1 units at the source.

(ii) If total SO2 emissions during a control period in a given year from the TR SO2 Group 1 units at a TR SO2 Group 1 source are in excess of the TR SO2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO2 Group 1 unit at the source shall hold the TR SO2 Group
1 allowances required for deduction under § 97.624(d); and

(B) The owners and operators of the source and each TR SO2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR SO2 Group 1 assurance provisions.

(i) If total SO2 emissions during a control period in a given year from all TR SO2 Group 1 units at TR SO2 Group 1

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sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO2 emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO2 Group 1 allowances available for deduction for such control period under § 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.625(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such SO2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such SO2 emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total SO2 emissions from all TR SO2 Group 1 units at TR SO2 Group 1 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the TR SO2 Group 1 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total SO2 emissions from all TR SO2 Group 1 units at TR SO2 Group 1 sources in a State (and Indian country within
the borders of such State) during a control period in a given year exceed the State assurance level if such total SO2 emissions exceed the sum, for such control period, of the State SO2 Group 1 trading budget under § 97.610(a) and the State's variability limit under § 97.610(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total SO2 emissions from all TR SO2 Group 1 units at TR SO2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total SO2 emissions from the TR SO2 Group 1 units at TR SO2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR SO2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods.

(i) A TR SO2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter.

(ii) A TR SO2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A TR SO2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a

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control period in a given year must be a TR SO2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR SO2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a TR SO2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR SO2 Group 1 allowance is a limited authorization to emit one ton of SO2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR SO2 Group 1 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO2 Group 1 allowance does not constitute a property right.

(d) Title V permit requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO2 Group 1 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO2 emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.630 through 97.635 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.616 for the designated representative for the source and each TR SO2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation;
provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 97.616 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO2 Group 1 Trading Program.

(2) The designated representative of a TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall make all submissions required under the TR SO2 Group 1 Trading Program, except as provided in § 97.618. This requirement

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does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability.

(1) Any provision of the TR SO2 Group 1 Trading Program that applies to a TR SO2 Group 1 source or the designated representative of a TR SO2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO2 Group 1 units at the source.

(2) Any provision of the TR SO2 Group 1 Trading Program that applies to a TR SO2 Group 1 unit or the designated representative of a TR SO2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the TR SO2 Group 1 Trading Program or exemption under § 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO2 Group 1 source or TR SO2 Group 1 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 032 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Transport Rule (TR) NOX Ozone Season Trading Program Requirements (40 CFR § 97.806)]

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.813 through 97.818.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.830 through 97.835.

(2) The emissions data determined in accordance with §§97.830 through 97.835 shall be used to calculate allocations of CSAPR NOX Ozone Season Group 2 allowances under §§97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NOX Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NOX emissions requirements
(1) CSAPR NOX Ozone Season Group 2 emissions limitation.
(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NOX Ozone Season Group 2 allowances available for deduction for such control period under §97.824(a) in an amount not less than the tons of total NOX emissions for such control period from all CSAPR NOX Ozone Season Group 2 units at the source.

(ii) If total NOX emissions during a control period in a given year from the CSAPR NOX Ozone Season Group 2 units at a CSAPR NOX Ozone Season Group 2 source are in excess of the CSAPR NOX Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each CSAPR NOX Ozone Season Group 2 unit at the source shall hold the CSAPR NOX Ozone Season Group 2 allowances required for deduction under §97.824(d); and

(B) The owners and operators of the source and each CSAPR NOX Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

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(2) CSAPR NOX Ozone Season Group 2 assurance provisions.

(i) If total NOX emissions during a control period in a given year from all base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NOX emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NOX Ozone Season Group 2 allowances available for deduction for such control period under §97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.825(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NOX emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NOX emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NOX emissions from all base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the CSAPR NOX Ozone Season Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(iii) Total NOX emissions from all base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NOX emissions exceed the sum, for such control period, of the State NOX Ozone Season Group 2 trading budget under §97.810(a) and the State's variability limit under §97.810(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NOX emissions from all base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NOX emissions from the base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold CSAPR NOX Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each CSAPR NOX Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods.

(i) A CSAPR NOX Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under §97.830(b) and for each control period thereafter.

(ii) A base CSAPR NOX Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under §97.830(b) and for each control period thereafter.

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(4) Vintage of CSAPR NOX Ozone Season Group 2 allowances held for compliance.

(i) A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR NOX Ozone Season Group 2 allowance that was allocated or auctioned for such control period or a control period in a prior year.

(ii) A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) of this section for a control period in a given year must be a CSAPR NOX Ozone Season Group 2 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NOX Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A CSAPR NOX Ozone Season Group 2 allowance is a limited authorization to emit one ton of NOX during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the CSAPR NOX Ozone Season Group 2 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NOX Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NOX Ozone Season Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NOX emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.830 through 97.835 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.816 for the designated representative for the source and each CSAPR NOX Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.816 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NOX Ozone Season Group 2 Trading Program.

SECTION E. Source Group Restrictions.

(2) The designated representative of a CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NOX Ozone Season Group 2 Trading Program, except as provided in §97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability.

(1) Any provision of the CSAPR NOX Ozone Season Group 2 Trading Program that applies to a CSAPR NOX Ozone Season Group 2 source or the designated representative of a CSAPR NOX Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NOX Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NOX Ozone Season Group 2 Trading Program that applies to a CSAPR NOX Ozone Season Group 2 unit or the designated representative of a CSAPR NOX Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CSAPR NOX Ozone Season Group 2 Trading Program or exemption under §97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NOX Ozone Season Group 2 source or CSAPR NOX Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

[Note: On July 6, 2011, EPA promulgated the Cross-State Air Pollution Rule (CSAPR) to replace CAIR. The CSAPR provisions of 40 CFR Part 97, Subpart AAAAA (relating to CSAPR NOx Annual Trading Program), replaced the provisions of 40 CFR Part 96, Subpart AA (relating to CAIR NOx Annual Trading Program General Provisions), and remain in effect. On October 26, 2016, EPA promulgated the CSAPR Update to establish the provisions of 40 CFR Part 97, Subpart EEEEE (relating to CSAPR NOx Ozone Season Group 2 Trading Program), to replace the previously-established CAIR NOx Ozone Season Trading Program and CSAPR NOx Ozone Season Group 1 Trading Program for certain states, including Pennsylvania, beginning with the 2017 ozone season. On April 30, 2021, EPA promulgated the Revised CSAPR Update to establish the provisions of 40 CFR Part 97, Subpart GGGGG (relating to CSAPR NOx Ozone Season Group 3 Trading Program), to replace the provisions of 40 CFR Part 97, Subpart EEEEE, for certain states, including Pennsylvania, beginning with the 2021 ozone season (though DEP will accept CSAPR NOx Ozone Season Group 2 allowances of current year vintage from other states, if available). Accordingly, the permittee shall surrender CSAPR NOx Annual allowances and CSAPR NOx Ozone Season Group 2 allowances, CSAPR NOx Ozone Season Group 3 allowances or CSAPR NOx Ozone Season Expanded Group 2 allowances, as defined in 40 CFR §§ 97.402, 97.802, and 97.1002, respectively, instead of the CAIR NOx allowances and CAIR NOx Ozone Season allowances indicated in 25 Pa. Code § 129.204(c), as the latter are no longer available.]

***** Permit Shield in Effect. *****

SECTION E. Source Group Restrictions.

Group Name: OIL STORAGE

Group Description: No.2 and fuel Oil Storage Tanks

Sources included in this group

ID	Name
122	#2 OIL STORAGE TANK (1.05 MMGAL)
123	FUEL OIL STORAGE TANKS(2)

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

 # 001 [25 Pa. Code §127.511]

Monitoring and related recordkeeping and reporting requirements.

Fuel throughput shall be monitored on a weekly basis.

IV. RECORDKEEPING REQUIREMENTS.

 # 002 [25 Pa. Code §127.511]

Monitoring and related recordkeeping and reporting requirements.

Fuel throughput shall be recorded on a weekly basis.

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

***** Permit Shield in Effect. *****

SECTION E. Source Group Restrictions.

Group Name: TURBINES

Group Description: Diesel / Kerosene Peaking Turbines

Sources included in this group

ID	Name
037	NO. 10 COMBUSTION TURBINE
038	NO. 20 COMBUSTION TURBINE
039	NO. 30 COMBUSTION TURBINE
040	NO. 40 COMBUSTION TURBINE

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person may permit the emission into the outdoor atmosphere of particulate matter from these turbines at any time, in excess of 0.027 gr/dscf, pursuant to 25 Pa. Code § 123.13 (c)(1)(ii).

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission into the outdoor atmosphere of sulfur oxides from these turbines in a manner that the concentration of the sulfur oxides, expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Only No. 2 fuel oil, kerosene, or a mixture of kerosene and No.2 fuel oil shall be burned in these turbines.

Throughput Restriction(s).

 # 004 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §129.112(c)(9)]

(a) The annual capacity factor for each turbine shall not exceed 5%.

(b) The annual capacity factor is the ratio of the unit's actual electric output (expressed in MWe/hr) to the unit's nameplate capacity [or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity] multiplied by 8,760 hours during a period of 12 consecutive calendar months.

[Compliance with this condition assures compliance with RACT II requirements under 25 Pa. Code §129.97(g)(2).]

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

 # 005 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The net electrical power generated (MWH) by each turbine shall be monitored monthly.

 # 006 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The permittee shall monitor the fuel usage and hours of operation for each of these turbines on a monthly basis.

SECTION E. Source Group Restrictions.

IV. RECORDKEEPING REQUIREMENTS.

 # 007 [25 Pa. Code §127.512]
Operating permit terms and conditions.

The following information shall be recorded for each turbine:

(a) certification from the fuel supplier of the type of fuel; and
(b) monthly electrical power (MWe/hr) generated for this turbine.

 # 008 [25 Pa. Code §127.512]
Operating permit terms and conditions.

Sufficient records and calculations shall be performed to demonstrate compliance with each emission limit for each turbine.

 # 009 [25 Pa. Code §127.512]
Operating permit terms and conditions.

For each turbine, the follwoing shallbe recorded:

(a) The net electrical power generated (MWH) shall be recorded monthly.

(b) The annual capacity factor shall be calculated and recorded monthly.

 # 010 [25 Pa. Code §127.512]
Operating permit terms and conditions.

The permittee shall record the fuel usage and hours of operation for each turbine on a monthly basis.

V. REPORTING REQUIREMENTS.

 # 011 [25 Pa. Code §127.512]
Operating permit terms and conditions.

Annual reports of fuel consumption, hours of operation, and megawatts generated by these turbines and generators shall be made available to the Department upon request.

VI. WORK PRACTICE REQUIREMENTS.

 # 012 [25 Pa. Code §127.512]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.97(c). and 129.112(c)]

These turbines shall be operated and maintained in accordance with manufacturers specifications and with good operating practices.

 # 013 [25 Pa. Code §129.202]
Stationary combustion turbines.

(a) By October 31 of each year, the permittee shall calculate the difference between the actual emissions from each stationary combustion turbine for the period from May 1 through September 30 and the allowable emissions for that period.

(b) The permittee shall calculate allowable emissions by multiplying the unit's cumulative heat input for the period by the applicable emission rate set forth below

(1) The emission rate for a stationary simple cycle combustion turbine with a nameplate rated capacity of greater than 100 million Btu/hour but less than or equal to 250 million Btu/hour heat input shall be as follows:

(A) When firing natural gas or a noncommercial gaseous fuel, 0.20 lbs NOx/MMBtu or 2.2 lbs NOx/MWH.
(B) When firing oil, 0.30 lbs NOx/MMBtu or 3.0 lbs NOx/MWH.

(2) The emission rate for a stationary combustion turbine with a nameplate rated capacity of greater than 250 million Btu/hour heat input that is not subject to § 145.8(c) or (d) is 0.17 lbs NOx per million Btu heat input.

 # 014 [25 Pa. Code §129.204]
Emission accountability.

SECTION E. Source Group Restrictions.

(a) If the affected source(s) has NOx CEMS, the permittee shall determine actual emissions in accordance with the CEMS data reported to the Department. Any data invalidated under Chapter 139 (relating to sampling and testing) shall be substituted with data calculated using the potential emission rate for the unit or, if approved by the Department in writing, an alternative amount of emissions that is more representative of actual emissions that occurred during the period of invalid data.

(b) If the permittee is not required to monitor NOx emissions with a CEMS, one of the following shall be used to determine actual emissions of NOx:

(1) The 1-year average emission rate calculated from the most recent permit emission limit compliance demonstration test data for NOx.

(2) The maximum hourly allowable NOx emission rate contained in the permit or the higher of the following:

(i) The highest rate determined by use of the emission factor for the unit class contained in the most up-to-date version of the EPA publication, ''AP-42 Compilation of Air Pollution Emission Factors.''

(ii) The highest rate determined by use of the emission factor for the unit class contained in the most up-to-date version of EPA's ''Factor Information Retrieval (FIRE)'' data system.

(3) CEMS data, if the permittee elects to monitor NOx emissions with a CEMS. The permittee shall monitor emissions and report the data from the CEMS in accordance with Chapter 139 or Chapter 145 (relating to interstate pollution transport reduction). Any data invalidated under Chapter 139 shall be substituted with data calculated using the potential emission rate for the unit or, if approved by the Department in writing, an alternative amount of emissions that is more representative of actual emissions that occurred during the period of invalid data.

(4) An alternate calculation and recordkeeping procedure based upon emissions testing and correlations with operating parameters. The permittee shall demonstrate that the alternate procedure does not underestimate actual emissions throughout the allowable range of operating conditions. In regard to obtaining the Department's approval for an alternate calculation method and recordkeeping procedure for actual emissions, the permittee may request an adjustment to the allowable emissions calculations set forth in § § 129.201—129.203. An allowable emission adjustment may not overestimate a unit's allowable emissions and must be based upon the parameters and procedures proposed in the alternate calculation method for actual emissions. The alternate calculation and recordkeeping procedures must be approved by the Department, in writing, prior to implementation.

 # 015 [25 Pa. Code §129.204]

Emission accountability.

(a) The permittee shall surrender to the Department one CAIR NOx allowance and one CAIR NOx Ozone Season allowance, as defined in 40 CFR 96.102 and 96.302 (relating to definitions), for each ton of NOx by which the combined actual emissions exceed the allowable emissions of the units subject to this section at a facility from May 1 through September 30. The surrendered allowances shall be of current year vintage. For the purpose of determining the amount of allowances to surrender, any remaining fraction of a ton equal to or greater than 0.50 ton is deemed to equal 1 ton and any fraction of a ton less than 0.50 ton is deemed to equal zero tons.

(b) If the combined allowable emissions from units subject to this section at a facility from May 1 through September 30 exceed the combined actual emissions from units subject to this section at the facility during the same period, the permittee may deduct the difference or any portion of the difference from the amount of actual emissions from units subject to this section at the permittee's other facilities.

(c) By November 1 of each year, the permittee shall surrender the required NOx allowances to the Department's designated NOx allowance tracking system account and provide to the Department, in writing, the following:

(1) The serial number of each NOx allowance surrendered.
(2) The calculations used to determine the quantity of NOx allowances required to be surrendered.

SECTION E. Source Group Restrictions.

(d) If the permittee fails to comply with subsection (c), the permittee shall by December 31 surrender three NOx allowances of the current or later year vintage for each NOx allowance that was required to be surrendered by November 1 of that year.

(e) The surrender of NOx allowances under subsection (d) does not affect the liability of the permittee for any fine, penalty or assessment, or an obligation to comply with any other remedy for the same violation, under the CAA or the act.

(1) For purposes of determining the number of days of violation, if a facility has excess emissions for the period May 1 through September 30, each day in that period (153 days) constitutes a day in violation unless the permittee demonstrates that a lesser number of days should be considered.
(2) Each ton of excess emissions is a separate violation.

[Note: On July 6, 2011, EPA promulgated the Cross-State Air Pollution Rule (CSAPR) to replace CAIR. The CSAPR provisions of 40 CFR Part 97, Subpart AAAAA (relating to CSAPR NOx Annual Trading Program), replaced the provisions of 40 CFR Part 96, Subpart AA (relating to CAIR NOx Annual Trading Program General Provisions), and remain in effect. On October 26, 2016, EPA promulgated the CSAPR Update to establish the provisions of 40 CFR Part 97, Subpart EEEEE (relating to CSAPR NOx Ozone Season Group 2 Trading Program), to replace the previously-established CAIR NOx Ozone Season Trading Program and CSAPR NOx Ozone Season Group 1 Trading Program for certain states, including Pennsylvania, beginning with the 2017 ozone season. On April 30, 2021, EPA promulgated the Revised CSAPR Update to establish the provisions of 40 CFR Part 97, Subpart GGGGG (relating to CSAPR NOx Ozone Season Group 3 Trading Program), to replace the provisions of 40 CFR Part 97, Subpart EEEEE, for certain states, including Pennsylvania, beginning with the 2021 ozone season (though DEP will accept CSAPR NOx Ozone Season Group 2 allowances of current year vintage from other states, if available). Accordingly, the permittee shall surrender CSAPR NOx Annual allowances and CSAPR NOx Ozone Season Group 2 allowances, CSAPR NOx Ozone Season Group 3 allowances or CSAPR NOx Ozone Season Expanded Group 2 allowances, as defined in 40 CFR §§ 97.402, 97.802, and 97.1002, respectively, instead of the CAIR NOx allowances and CAIR NOx Ozone Season allowances indicated in 25 Pa. Code § 129.204(c), as the latter are no longer available.]

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

***** Permit Shield in Effect. *****

SECTION F. Alternative Operation Requirements.

No Alternative Operations exist for this Title V facility.

SECTION G. Emission Restriction Summary.

Source Id	Source Description
033	BOILER 3

Emission Limit			Pollutant
0.100	Lbs/MMBTU	firing natural gas, RACT II and III	NOX
0.120	Lbs/MMBTU	firing No. 2 oil, RACT II and III	NOX
0.290	Lbs/MMBTU	Boilers 3 & 4 combined, RACT I	NOX
5,568.000	Tons/Yr	Boilers 3 & 4 combined, RACT I	NOX
0.100	Lbs/MMBTU	Particulate matter per stack	TSP
0.100	Lbs/MMBTU	Particulate matter per stack, combined Boilers 3 & 4	TSP
0.002	Lbs/MMBTU	Boilers 3 & 4 combined emissions	VOC
35.900	Tons/Yr	Boilers 3 & 4 combined emissions	VOC

034	AUXILIARY BOILER A

Emission Limit			Pollutant
130.000	PPMV	drybasis, corr to 3% O2, or 0.13 lb per MMBtu of steam output. (fuel oil)	CO
130.000	PPMV	drybasis, correct to 3% O2, or 0.13 lb/MMBtu of steam output firing fuel oil	CO
0.001	Lbs/MMBTU	or 1.4E-03 lb per MMBtu of steam output. (fuel oil)	Hydrochloric Acid
0.001	Lbs/MMBTU	or 1.4E-03 lb/MMBtu of steam output firing fuel oil	Hydrochloric Acid
0.005	gr/MMBTU	or 8.8E-07 lb/MMBtu of steam output firing fuel oil	Mercury
0.014	gr/MMBTU	or 2.5E-06 lb per MMBtu of steam output. (fuel oil)	Mercury
0.100	Lbs/MMBTU	Firing natural gas, RACT III	NOX
0.120	Lbs/MMBTU	Firing No. 2 oil, RACT III	NOX
36.000	Tons/Yr		NOX
0.053	gr/MMBTU	1.4E-05 lb per MMBtu of steam output. (natural gas)	SO2
0.008	Lbs/MMBTU	or 9.6E-03 lb/MMBtu of steam output firing fuel oil (filterable PM only)	TSP
0.079	Lbs/MMBTU	or 9.6E-03 lb per MMBtu of steam output (filterable PM only). (fuel oil)	TSP
0.240	Lbs/MMBTU	Particulate Matter	TSP

035	AUXILIARY BOILER B

Emission Limit			Pollutant
130.000	PPMV	drybasis, corr to 3% O2, or 0.13 lb per MMBtu of steam output. (fuel oil)	CO
130.000	PPMV	drybasis, correct to 3% O2, or 0.13 lb/MMBtu of steam output firing fuel oil	CO
0.001	Lbs/MMBTU	or 1.4E-03 lb per MMBtu of steam output. (fuel oil)	Hydrochloric Acid
0.001	Lbs/MMBTU	or 1.4E-03 lb/MMBtu of steam output firing fuel oil	Hydrochloric Acid
0.005	gr/MMBTU	or 8.8E-07 lb/MMBtu of steam output firing fuel oil	Mercury
0.014	gr/MMBTU	or 2.5E-06 lb per MMBtu of steam output. (fuel oil)	Mercury
0.100	Lbs/MMBTU	Firing natural gas, RACT III	NOX

SECTION G. Emission Restriction Summary.

Source Id	Source Description

0.120	Lbs/MMBTU	Firing No. 2 oil, RACT III	NOX
36.000	Tons/Yr		NOX
0.053	gr/MMBTU	1.4E-05 lb per MMBtu of steam output. (natural gas)	SO2
0.008	Lbs/MMBTU	or 9.6E-03 lb/MMBtu of steam output firing fuel oil (filterable PM only)	TSP
0.079	Lbs/MMBTU	or 9.6E-03 lb per MMBtu of steam output (filterable PM only). (fuel oil)	TSP
0.240	Lbs/MMBTU	Particulate Matter	TSP

036 AUXILIARY BOILER C

Emission Limit			Pollutant
130.000	PPMV	drybasis, corr to 3% O2, or 0.13 lb per MMBtu of steam output. (fuel oil)	CO
130.000	PPMV	drybasis, correct to 3% O2, or 0.13 lb/MMBtu of steam output firing fuel oil	CO
0.001	Lbs/MMBTU	or 1.4E-03 lb per MMBtu of steam output. (fuel oil)	Hydrochloric Acid
0.001	Lbs/MMBTU	or 1.4E-03 lb/MMBtu of steam output firing fuel oil	Hydrochloric Acid
0.005	gr/MMBTU	or 8.8E-07 lb/MMBtu of steam output firing fuel oil	Mercury
0.014	gr/MMBTU	or 2.5E-06 lb per MMBtu of steam output. (fuel oil)	Mercury
0.100	Lbs/MMBTU	Firing natural gas, RACT III	NOX
0.120	Lbs/MMBTU	Firing No. 2 oil, RACT III	NOX
36.000	Tons/Yr		NOX
0.053	gr/MMBTU	1.4E-05 lb per MMBtu of steam output. (natural gas)	SO2
0.008	Lbs/MMBTU	or 9.6E-03 lb/MMBtu of steam output firing fuel oil (filterable PM only)	TSP
0.079	Lbs/MMBTU	or 9.6E-03 lb per MMBtu of steam output (filterable PM only). (fuel oil)	TSP
0.240	Lbs/MMBTU	Particulate Matter	TSP

041 BOILER 4

Emission Limit			Pollutant
0.100	Lbs/MMBTU	firing natural gas, RACT II and III	NOX
0.120	Lbs/MMBTU	firing No. 2 oil, RACT II and III	NOX
0.290	Lbs/MMBTU	Boilers 3 & 4 combined, RACT I	NOX
5,568.000	Tons/Yr	Boilers 3 & 4 combined, RACT I	NOX
0.100	Lbs/MMBTU	Particulate matter per stack	TSP
0.100	Lbs/MMBTU	Particulate matter per stack, combined Boilers 3 & 4	TSP
0.002	Lbs/MMBTU	Boilers 3 & 4 combined emissions	VOC
35.900	Tons/Yr	Boilers 3 & 4 combined emissions	VOC

SECTION G. Emission Restriction Summary.

Source Id	Source Description
037	NO. 10 COMBUSTION TURBINE

Emission Limit		Pollutant
500.000	PPMV	SO2
0.027	gr/DRY FT3	TSP

Source Id	Source Description
038	NO. 20 COMBUSTION TURBINE

Emission Limit		Pollutant
500.000	PPMV	SO2
0.027	gr/DRY FT3	TSP

Source Id	Source Description
039	NO. 30 COMBUSTION TURBINE

Emission Limit		Pollutant
500.000	PPMV	SO2
0.027	gr/DRY FT3	TSP

Source Id	Source Description
040	NO. 40 COMBUSTION TURBINE

Emission Limit		Pollutant
500.000	PPMV	SO2
0.027	gr/DRY FT3	TSP

Site Emission Restriction Summary

Emission Limit	Pollutant

SECTION H. Miscellaneous.

The Department has determined that the emissions from the following activities, excluding those indicated as site level requirements, in Section C, of this permit, do not require additional limitations, monitoring, or recordkeeping:

- Lube oil reservoirs and vents.
- Chemical storage tanks.
- Handling of wet solids.
- Oil-water seperator.
- Chemistry lab vents.
- Miscellaneous delivery truck traffic.

The following previously issued Operating Permits serve as the basis for certain terms and conditions set forth in this Title V Permit:

OP-23-00017A, as amended.

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On October 31, 2000, PECO Energy Co. requested that the Department change their name to Exelon Generation Company, LLC. On March 6, 2001, the Department accepted the name and address change, and the Title V permit has been revised to reflect these changes.

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September 2004. APS No. 346561; Authorization No. 562528: This Title V Permit has been administratively amended to incorporate the requirements of a plan approval (PA-23-0017A) in accordance with 25 Pa. Code § 127.450(a)(5). The plan approval (PA-23-0017A) was for the installation of Selective Non-Catalytic Reduction (SNCR) Systems on Boiler Nos. 1 and 2 (Source ID Nos. 031 and 032). Added requirements include a limit on the amount of ammonia emitted from the stack of 10 ppmdv and monitoring and recordkeeping of the amount of reagent being injected whenever the SNCR Systems are in operation.

Other Administrative Changes Made to This Permit Under This Revision

(a). The Responsible Official Contact information was changed to reflect the current responsible official at this facility.
(b). Section C Condition #021 - The tiered monitoring approach for facility-wide monitoring for odors, visible emissions, and fugitive particulate matter replaces an older version requiring the facility to monitor once per day for odors, visible emissions, and fugitive particulate matter through the effective dates of the permit.
(c). Section C Condition #021 - a reference to another condition number in this permit was removed and replaced by a direct reference to 25 Pa. Code § 123.43.
(d). The phone number for Air Quality was corrected in Section C Condition #029 to reflect the Department's move to the new office building in Norristown, PA.
(e). The response time for the facility to call the Department in case of a malfunction (Section C, Condition #029(a)) was changed from "one hour" to "two hours."
(f). NOx Budget Account Representatives at this facility have changed since the initial issuance of this permit. The permit has been changed to reflect this change in personnel.
(g). For Condition #038 under Source ID No. 031, all scrubber trains are utilized in controlling particulate matter and sulfur dioxide. There is no back-up scrubber. This was incorrectly described in the Title V Permit, and the condition was changed to correctly describe the operation of this source at this facility.
(h). For Source ID Nos. 033 and 041, CEM Systems measure sulfur dioxide emissions for the acid rain program only. References to 25 Pa. Code Chapter 139 were removed since the facility is not required by the Department to monitor and record sulfur dioxide emissions from these sources by using CEMS. CEMS are only used in these sources in the Acid Rain Program.

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December, 2004, APS No.: 570416, AUTH ID: 570461. The Department amended this permit for cause to incorporate the Acid Rain (Title IV) renewal permit into the Title V permit.

_____

September, 2008. APS: 346561, AUTH: 643648. The Department renewed this permit. No new sources have been added since the last amendment.
- Several new regulations have become applicable, these are: Small NOx regulations for the four (4) turbines, the state's Mercury Rule, and 40 CFR, Subpart 64 (CAM). Sources 031 and 032 are subject to each of these and they have been incorporated into this renewal permit.
- Coal Car Thaw Pit (Source 124) has been removed from the permit at the request of Exelon.
- At the request of DEP Central Office, the Acid Rain (Title IV) permit has been removed from the TVOP and is its own stand-alone operating permit.
- Submittal dates for the annual compliance certification and semi-annual deviation reports have been changed to April 1 and October 1, respectively.

SECTION H. Miscellaneous.

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May, 2008. APS: 346561, AUTH: 711670. Major modification to incorporate the federal CAIR regulations. The Department removed the permit conditions pertaining to mercury as these regulations have been withdrawn.

_____
November 2013. APS: 346561,AUTH: 971592. Permit renewal.
- The following sources have been shut down and the the ERCs generated: Boiler 1 (source 031) in February 2011, Boiler 2, (Source 032), Centrifuge Dryers (Sources 113 & 114), and the Coal Handling Fugitives (Source F01) all in April 2011. The above shutdowns include the respective control devices for these sources.
- New applicable regulations for this facility include NESHAP DDDDD, UUUUU for the boilers.
- RFDs incorporated are: 699, 1019, 1593, 2091, and 2332.
- Incorporated the Acid Rain Permit (Title IV) ORIS number 3161 into the TVOP.

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February 2015. APS: 346561, Auth: 1059904. Permit amendment to address a change in the federal regulation regarding tuneup date requirements for Sources 031, 032, 033, and 041. This is to match the changes made in 40 CFR § 63.10005(f) for existing EGUs without a neural network..

April 2015. APS: 346561, Auth: 1067454. Administrative amendment to address a change in the responsible official from Paul Weeks to Bryan Bennett.

_____
December 2015. APS: 346561, AUTH: 1100105. Administrative amendment to address a change in the federal regulations (40 CFR § 63.7510(e), which allows for an additional 180 days to demonstrate initial compliance with the emission limits for Sources 034, 035, and 036, all subject to Subpart DDDDD).

_____
August 2017. APS: 346561, Auth 1188054. Administrative amendment to address the emission limits and testing for Total Select Metals (TSM) as allowed by 40 CFR 63, Subpart DDDDD.

_____
March 2019. APS: 346561,AUTH: 1231260. Permit renewal.
- RFD No. 4386 and applicable RACT II requirements are incorporated into the permit.
- Acid Rain Permit (Title IV, ORIS number 3161) is a stand-alone permit issued by DEP effective January 1, 2018 through December 31, 2022. All permit conditions associated with Acid Rain Permit are removed.
- CSAPR conditions are added and CAIR conditions are removed.
- Applicable requirements of 40 CFR Part 63 Subpart DDDDD are added for Sourced ID 042.

____
April 2025: AUTH 1450624: APS 346561. Renewal of TVOP. Update of RACT III requirements for all boilers; update of requirements for main boilers under 40 CFR Part 63 Subpart UUUUU; update of requirements for auxiliary boilers under 40 CFR Part 63 Subpart DDDDD.

****** End of Report ******

Exhibit 5

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Attachment C

Affidavit of Adam Keech
on Behalf of
PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER24-___-000**

AFFIDAVIT OF ADAM KEECH
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

Qualifications

1. My name is Adam Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am the Vice President of Market Design and Economics at PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its capacity market reform filing. In my current role I oversee the design of all of the wholesale markets operated by PJM and the development of large-scale advanced analyses such as those done for carbon pricing and renewable integration. I am also responsible for the applied innovation area that focuses on evaluating, leveraging and supporting the implementation of advanced solutions in the planning, markets and operations areas. I have worked for PJM since 2003 and held senior leadership roles in both the Market Services and System Operations divisions. I earned a Bachelor of Science in electrical engineering from Rutgers University in 2002 and earned a Master of Science in applied statistics from West Chester University in 2013.

Purpose of This Affidavit

2. The purpose of my affidavit is to first explain the importance of the capacity market's role as part of the overall suite of PJM's markets and describe the motivation to seek changes now. As explained in my affidavit and in various other work performed by PJM, the industry is in a period of rapid change. While the foundation of PJM's markets is strong, it is necessary to evaluate their designs in light of the change in the industry to ensure they are configured to continue to provide reliability at low cost to consumers and send efficient price signals for performance, entry and exit. From there I go on further to explain the rationale for specific, necessary, enhancements including a move to marginal accreditation, stronger testing requirements and a collection of changes to the Fixed Resource Requirement option.

Why is the Capacity Market Necessary?

3. The capacity market is necessary because the energy and ancillary services ("E&AS") markets do not consistently produce sufficient revenues to support investment in sufficient resources to maintain the desired level of reliability (one

loss of load event in ten years, on average). This lack of revenues, or "missing money", comes from two primary causes:

a. Limitations on the revenues permitted to be settled in the E&AS due to rules such as offer and price cap levels, and,

b. A desire not to shed load at a frequency greater than one event every ten years, on-average.

4. The purpose of my affidavit is not to argue merits of those rules; however, it is helpful to understand them as key drivers that lead to the "missing money" problem that PJM uses the Reliability Pricing Model (RPM) to address.

5. At its core, capacity is a reserve product. The product itself is generation or load curtailment capability to provide enough supply to, at a minimum, meet the desired level of reliability. The revenues from the sale of the product go directly towards addressing the revenue gap between those produced by the E&AS markets and those necessary to meet the desired level of reliability. PJM uses a uniform clearing price market to procure the capacity product at least cost in the short- and long-term by harnessing the benefit of competition.

6. In the PJM market where approximately 70% of the load is in a state that has restructured its retail electricity market, a functioning capacity market like the RPM is required to procure adequate supply to meet the desired level of reliability in any given Delivery Year. In general, supply resources in restructured states do not receive cost recovery through a state agency and therefore rely on the capacity market and E&AS markets in PJM for the vast majority their revenues. Failure of the capacity market to perform can result in a shortfall supply relative to the amount necessary to maintain desired level of reliability resulting in frequent load-shedding events, or excess capacity whose costs exceed its reasonable incremental impact to reliability. Neither of these outcomes are desirable and therefore careful thought must be put into the various parameters of the capacity market to result in just and reasonable outcomes.

Why Are We Changing the Capacity Market?

7. Since the start of the Resource Adequacy Senior Task Force (RASTF) in late-2021, a primary motivator of PJM's focus on capacity market reforms has been to enhance its resource adequacy risk modeling and accreditation methods. Historically, resource adequacy risk modeling and accreditation methods have relied on assumptions that:

a. Resource adequacy risk is aligned with peak load conditions,

b. Generator outages are independent of each other, and,

c. Average historical performance is a reasonable estimate of future performance during resource adequacy risk periods.

8. For decades, these assumptions have generally held true and have shaped the way the industry thinks about resource adequacy. However, over the last decade, evidence has emerged that these assumptions may no longer be workable and that a fresh look at resource adequacy risk modeling and accreditation is needed to provide for reliability both now and in the future.

9. In the recently released presentation titled, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations", NERC and FERC highlight that Winter Storm Elliott represents the fifth event where, "cold weather-related generation outages jeopardized bulk power system reliability".[1] Two of those five events, the 2014 Polar Vortex and Winter Storm Elliott in 2022, directly impacted PJM. In fact, the 2014 Polar Vortex spurred the implementation of Capacity Performance in 2015, and Winter Storm Elliott introduced a significant number of action items and recommendations,[2] several of which are being addressed in PJM's proposal. The statement by NERC and FERC very succinctly captures the need to reform resource adequacy risk modeling and accreditation as it highlights two issues:

   a. Bulk power system reliability was jeopardized in the winter, not summer. PJM is not a winter-peaking system in terms of load, but in recent years the resource adequacy risk has been empirically observed in the winter. This demonstrates that, at least for PJM, the existing resource adequacy risk modeling assumption of risk aligning with primarily with peak load is incorrect.

   b. The aforementioned resource adequacy risk was driven by generation outages that were correlated with temperature; in this case cold weather. This communicates a few things:

      i. Poor fleet performance, on its own, can create resource adequacy risk. This was the case in the 2014 Polar Vortex and Winter Storm Elliott in 2022. Establishing a model where resource performance can be a driver of reliability risk is essential.

      ii. Generator outages are correlated with temperature. FERC and NERC highlight that this is the fifth instance of this in the last 11 years which demonstrates that these are not anomalous observations.

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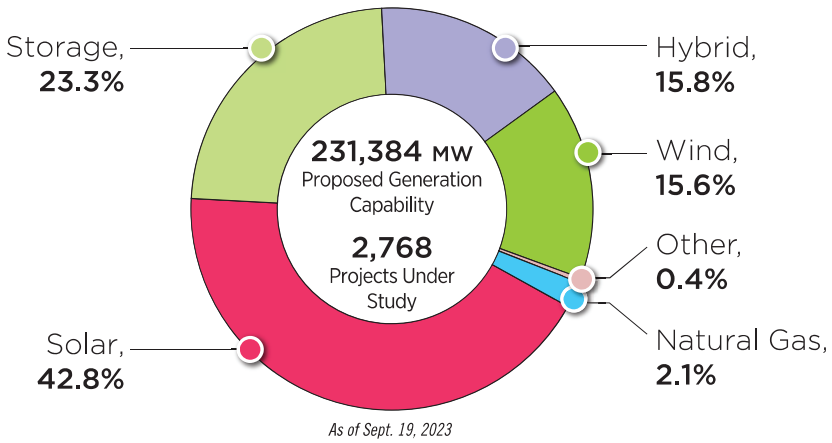
[1] FERC, NERC, and Regional Entity Joint Staff Inquiry, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations*, Federal Energy Regulatory Commission, 3 (Sept. 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[2] *Winter Storm Elliott: Event Analysis and Recommendation Report*, PJM Interconnection, L.L.C. (July 17, 2023), https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

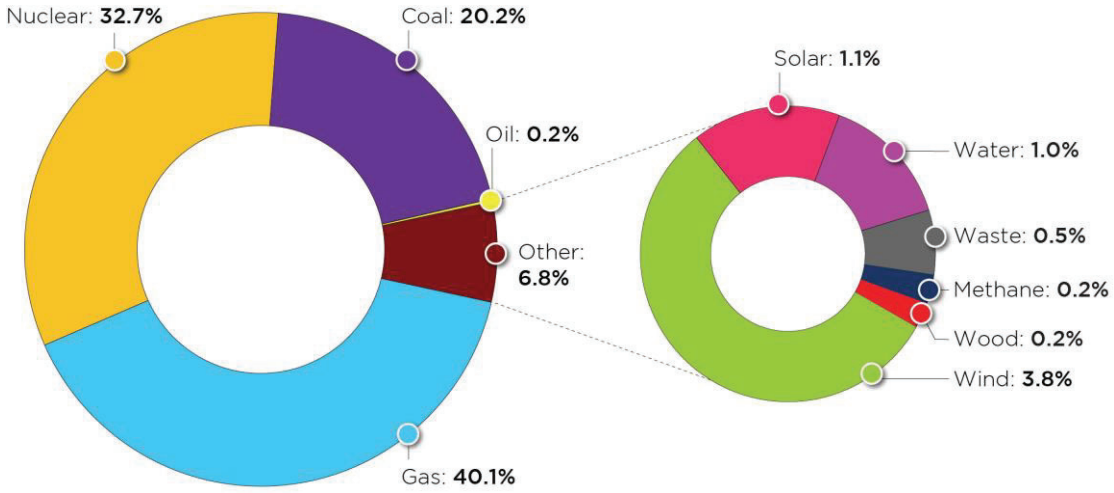
10. Further motivating the need for capacity market reform is the ongoing energy transition. As shown in Figure 1, PJM's current generation interconnection queue is primarily composed of solar, storage, hybrid resources and wind. Today in PJM, the penetration levels of these resource types are relatively low in comparison to the shares that exist in the queue and what is interconnected in other ISO/RTOs. PJM anticipates that the penetration of these resources will increase in the future based on what is in the PJM generation interconnection queue and the continued growth of these resource types in other areas of the country. Because these resources have different operating profiles than those that they stand to replace[3], implementing a method to accurately value the capacity capability of these resources and assess how their performance effects resource adequacy risk is critical to maintaining resource adequacy through the energy transition.



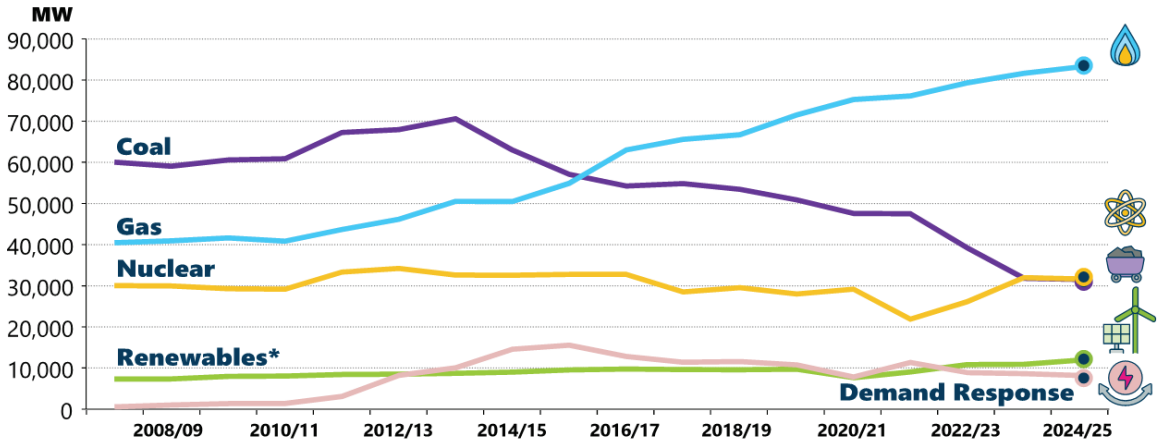
11. Another event that has already substantially impacted the demographics of the PJM generation fleet is the "shale gas revolution" that has occurred over roughly the last decade. This has resulted in the transition to natural gas as the primary fuel for the production of energy in PJM and the primary resource type providing capacity in PJM.

[3] Different operating profiles between solar, wind, storage and hybrid resources include, for solar and wind, correlation between output level and weather conditions that may not align with resource adequacy risk periods and for storage and hybrid resources, energy limitations related to storage capability and weather conditions.

2022 PJM Fuel Mix



Committed Unforced Capacity in PJM



**Renewables include solar, wind, hydro and wood. Note: All values include capacity cleared in RPM BRA or committed in FRR plan*

12. Many of these new gas-fired resources are incredibly flexible and provide much-needed reliability attributes. However, their performance is subject to the rules and restrictions of the interstate natural gas pipeline and production systems which, in terms of resource adequacy risk modeling, represents a common-mode failure that was a factor in their performance during the 2014 Polar Vortex and Winter Storm Elliott that led to resource adequacy risk. In PJM, changes to the resource fleet that have already occurred from the "shale gas revolution" and stand to occur due to the energy transition stand to create a generation fleet whose performance is more dependent on exogenous factors than ever experienced with previous resource mixes. In the case of renewable resources, they are dependent on weather patterns that do not always align with resource adequacy risk conditions. In the case of natural gas-fired resources, upstream limitations on pipeline capacity and production can adversely affect a broad set of resources in the PJM footprint simultaneously. These common-mode failures of supply-side resources are not

accurately represented in the current resource adequacy risk modeling and accreditation approaches and on their own can result in resource adequacy risk.

13. The need to depart from the legacy assumptions of (i) the alignment of resource adequacy risk with peak load conditions, (ii) independence of generator outages, and (iii) using average availability as an estimate of performance during risk periods, has required PJM to significantly enhance its resource adequacy risk modeling and accreditation approach to incorporate hourly granularity and the explicitly modeling of correlated outages as described in detail by Dr. Rocha-Garrido. These changes will more robustly determine periods of resource adequacy risk and more accurately estimate resource performance during those risk periods. In turn, these changes will allow PJM to better accredit the capacity capability of each resource by identifying each resource's relative reliability value to the PJM Region. Further, these changes have downstream impacts on the parameters that apply to the capacity market and the incentives that need to be sent to maintain resource adequacy cost-effectively in the short- and long-term.

Marginal Accreditation

14. Capacity accreditation is the process whereby PJM converts the nameplate capability of a resource to an accredited level of capacity that it may offer to sell in an auction. Under today's rules PJM uses average Effective Load Carrying Capability (ELCC) for intermittent, storage and combination resources, Equivalent Demand Forced Outage Rate (EFORd) for thermal resources (i.e., Unlimited Resources), and nominated capability times the Forecast Pool Requirement (FPR) for Demand Response (DR). Each of these methodologies is based on different performance assumptions for each resource type. For example, using EFORd for thermal resources assumes that the average historical performance of a thermal generator is a good approximation of future performance during risk periods. Using average ELCC for intermittent resources accredits based on the expected alignment of resource performance with risk conditions. For DR, the use of FPR as the sole component to determine accreditation assumes DR are always available during risk conditions and always perform perfectly. Each of these approaches have shortcomings but the shortcomings of each approach are different and affects accreditation of the applicable resource type in a different way.

15. Through this filing, PJM proposes to move to a marginal ELCC approach for all Capacity Resource types except of Energy Efficiency (EE) Resources.[4] Dr. Rocha-Garrido details in his affidavit how the marginal ELCC accreditation approach works. There are several drivers for this change:

    a. PJM seeks to unify its accreditation approach across all resources so there is consistency in the accreditation process.

[4] PJM Forward Market Operations, *PJM Manual 18B: Energy Efficiency Measure & Verification*, PJM Interconnection, L.L.C. (Sept. 21, 2022), https://pjm.com/~/media/documents/manuals/m18b.ashx.

b. The marginal accreditation approach proposed by PJM naturally aligns the level of accredited capacity of resource with its expected performance during risk periods.

c. The marginal accreditation approach proposed by PJM sends investment signals that are consistent with the marginal benefit to reliability (in this proposal Expected Unserved Energy (EUE)) of a specific resource or class. This creates incentives to invest in resources and resource classes that directly benefit resource adequacy needs.

16. A consistent accreditation approach is important in treating the various supply resources in the capacity market and creating a reasonably uniform capacity product across the various resource types. Under the current rules it could be argued that certain resource classes may be advantaged, or disadvantaged, just because of the accreditation approach that is applied to them. The benefit of a single accreditation approach is even more critical because it creates a single, fungible capacity product which could be argued to not be the case under the current rules given the various accreditation methods used. A simple example is that the EFORd approach applied to thermal resources today values average historic performance without focused consideration of performance during risk periods, whereas the use of ELCC for intermittent, storage and combination resources values performance coincident with risk periods. The result is two different products that are not fungible yet are treated as such in the current design. A single accreditation approach for all resources addresses this issue. Using one method to accredit resources results in a common definition of the capacity product across the various resource types and allows for the creation of a single, fungible product.

17. The marginal ELCC approach proposed by PJM calculates the marginal benefit to reliability, measured as a reduction in EUE, resulting from an incremental increase in nameplate capability of that class. Each class-level marginal ELCC is then propagated to individual resources within the class based on each individual resource's actual performance relative to others in the same class. Accrediting in this manner for all resources establishes a uniform capacity product across each resource participating in the market but also has the secondary benefit of aligning the level of accredited capacity for a resource with its expected performance during periods of risk as identified in the resource adequacy risk models explained by Dr. Rocha-Garrido. This is a beneficial change because it more precisely estimates how a resource will perform during identified periods of resource adequacy risk rather than assuming average performance (EFORd) or perfect performance (current accreditation method for DR). Accrediting capacity resources based on expected performance during risk periods is critical to ensuring that the actual resource adequacy needs of the system are being met and that consumers paying for capacity are get the reliability they are paying for.

18. As an example, assume a 100 MW thermal resource is on a forced outage 5% of the time (438 hours per year) such that under the current rules it has 95 MW of accredited capacity. Under the current rules and with respect to accreditation, those

438 hours of forced outage can occur at any time during the year and it will result in the same accredited level of capacity. Whether the 438 hours of forced outages overlap with the riskiest hours in the year or they do not, the accredited value of capacity is the same. This is a major downside of average accreditation methods, that is, consumers pay for performance on average rather than specifically for performance during resource adequacy risk periods for which they purchase capacity. In the case of PJM today, Capacity Performance and the associated Non-Performance Charges and bonus payments send incentives to perform during risk hours, however, those events are infrequent in nature and absent aligning accreditation with expected performance during risk periods, consumers could pay such a resource for capacity, possibly for years in between events when the resource does not actually contribute to reliability consistent with the revenues it is collecting.

19. Marginal ELCC as proposed by PJM sends investment signals that are consistent with the marginal reliability benefit of a resource resulting in strong incentives to invest in resources that directly improve resource adequacy (measured as a reduction in EUE). In general, this occurs because the capacity product itself as defined by using marginal ELCC represents a resource's incremental benefit to reliability. Resources that do not perform well during risk conditions have lower contributions to overall system reliability, will have lower accredited levels and as such will collect less revenues than resources that perform well during risk periods and reduce the system's EUE. Dr. Graf explains this concept further through simulations in his affidavit.

20. Finally, the shift to a marginal accreditation approach is consistent with other ISO/RTOs which either have, or are working towards, similar enhancements. For instance, NYISO filed a marginal accreditation approach with the Commission in 2022 that has been accepted.[5] ISONE is currently working towards implementing a marginal accreditation approach, as is MISO. The movement of other ISO/RTOs towards marginal accreditation and the fact that the Commission has already found this approach to be just and reasonable gives further credence to the method. This approach represents the industry's best-known method to model the various factors that can influence resource performance during risk periods using standard statistical algorithms and results in market outcomes that incentivize investment in resources that benefit resource adequacy at least cost.

Testing

21. PJM is proposing several changes to its testing requirements that will require a demonstration of resource capability in both the summer and winter seasons and improve operational readiness prior to extreme weather events. The purpose of making these changes is to better balance the financial incentives for performance conveyed through Capacity Performance with actual demonstrations of capacity

[5] *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102 (2022).

resource capability prior to the Performance Assessment Intervals where Non-Performance Charges and bonus payments may apply.

22. PJM proposes three key changes:

    a. An additional requirement for capacity resources to physically perform a capability test in the winter in addition to the current requirement for summer capability testing, and,

    b. A change to the calculation of the MW shortfall used to determine whether a Generation Resource Test Failure Charge applies from the current average method to a daily assessment, and,

    c. The creation of a new test called the Generator Operation Test intended to test resource capability and operating parameter accuracy prior to periods of the year where PJM may experience extreme weather conditions.

23. PJM's current Generation Capacity Resource capability testing rules require only a single test to be conducted in the summer and permits the use of ambient temperature adjustments from the summer test result to demonstrate winter capability. At the end of each Delivery Year, the annual average of the installed capacity committed on each resource is compared to the highest installed capacity rating determined for the resource during the relevant summer or winter testing period and any shortfalls are assessed a Generation Resource Rating Test Failure Charge. The Generation Resource Rating Test Failure Charge is equal to the Daily Deficiency Rate multiplied by the MW shortfall where the Daily Deficiency Rate is the higher of the $20/MW-day or 1.2 * Weighted Average Clearing Price that the resource receives for the Delivery Year based on the MW quantities and clearing prices it receives from each auction it cleared in.

24. There are two shortcomings with this approach that PJM seeks to amend with this proceeding. First, empirical observations from Winter Storm Elliott and similar extreme events in other ISO/RTOs, as well as the analysis performed by Dr. Rocha-Garrido to determine the ELCC for capacity resources, clearly demonstrate that generators operate differently in the summer and winter. These observation and analyses indicate that the current method of extrapolating winter capability from summer capability through ambient temperature adjustments is not suitable to determine the true winter capability of a generation resource. The best way to assess both summer and winter capability is by requiring physical demonstrations of this capability in each season. As such, PJM proposes to require seasonal rating tests for each generation capacity resource with the details of those test to be defined in PJM manuals as they are today.

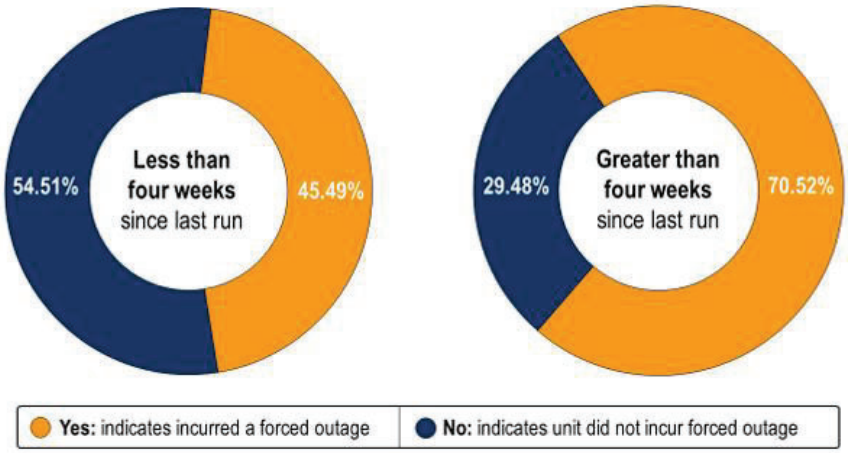
25. The second proposed change to the Generation Capacity Resource capability testing process is with regard to the calculation of the MW shortfall portion of the Generation Resource Test Failure Charge. Currently the Generation Resource Rating Test Failure Charge is calculated at the end of each Delivery Year and

includes MW shortfall calculation based on the *annual average* of the installed capacity committed on each resource minus the highest installed capacity rating determined for the resource during the relevant summer or winter testing period. That MW shortfall is then converted to an unforced capacity basis, and multiplied by the Daily Deficiency Rate. PJM's proposed change is with regard to the calculation of the MW shortfall only. PJM is not proposing to change the Daily Deficiency Rate. Rather, in calculating the MW shortfall, PJM proposes to assess the resource's MW shortfall on the daily installed capacity commitment of the resource instead of the annual average of the installed capacity committed on the resource. The rationale for this change is to more precisely determine whether the installed capacity the resource is committed for each day aligns with its demonstrated capability. The current process of using an annual average is directionally reasonable but can miss scenarios where on any given day a resource's committed installed capacity is higher than its demonstrated seasonal capability but when averaged annually is missed. The objective of this change is to have greater confidence that for every single day of the Delivery Year, each resource has demonstrated the capability to meet its capacity commitment. If it cannot, it will be assessed as deficient and subject to a Generation Resource Rating Test Failure Charge.

26. The third proposed change to Generation Capacity Resource testing is the implementation of a new testing process called Generation Capacity Resource Operational Testing. The purpose of this test is to have greater confidence that Generation Capacity Resources can operate successfully when called based on their submitted operating parameters. The intention of this test is to check that accurate information regarding the operational status and operating parameters of a Generation Capacity Resource are provided to PJM and that the Generation Capacity Resource can successfully demonstrate that through performance. This is particularly important for those Generation Capacity Resources that do operate frequently and may be asked to operate during a resource adequacy risk period after not running for several months.

27. The motivation for such a test comes from analysis done by PJM on generator performance during Winter Storm Elliott. Following that event, PJM analyzed and published the following chart regarding generation resource performance during Winter Storm Elliott. The following chart shows that resources that had run within a month of Winter Storm Elliott experienced a forced outage rate that was 25% percentage points lower than those that had not run as recently. This data supports the conclusion that a generator that has not operated recently and is asked to start in anticipation of or during a capacity emergency is at a higher risk of experiencing a forced outage than one that has operated more recently.

Force Outage Versus Last Run Time



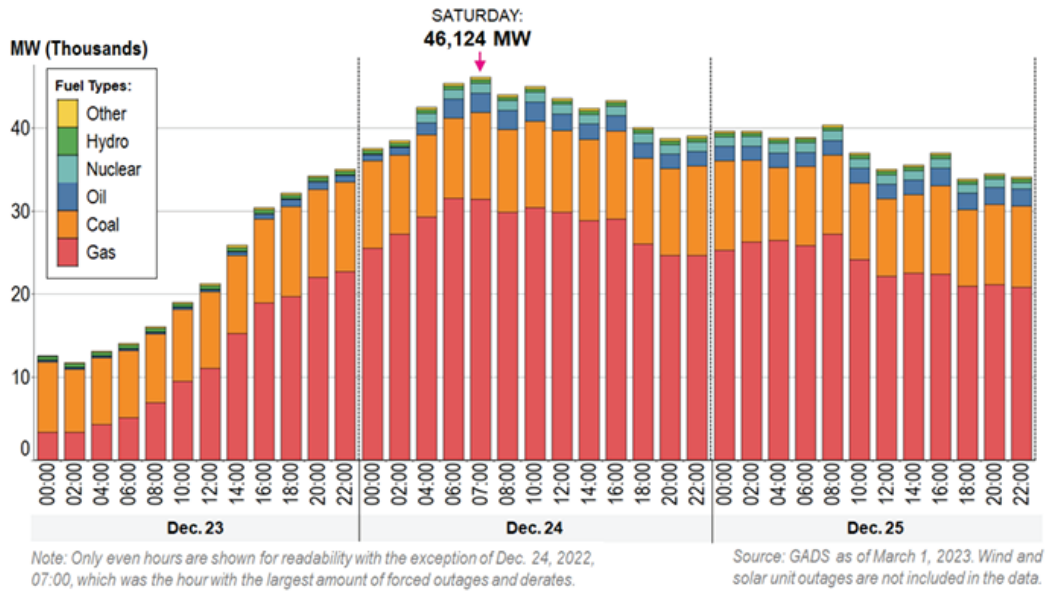
28. Further, during Winter Storm Elliott, PJM experienced a significant number of outages that were mechanical in nature. The following charts show two key points:

    a. On the first chart, approximately 75% of the generator forced outages experienced during Winter Storm Elliott were from generation resources whose fuel was natural gas, and

    b. On the second chart, only approximately 25% of those outages to natural gas units were related to "Gas Supply" issues.

29. In short, over 80% of the outages experienced during Winter Storm Elliott were mechanical in nature. PJM interprets this data to show that there is an opportunity to enhance testing and better balance the demonstration of performance through testing with the financial incentives conveyed through Capacity Performance. While it is impossible to test Generation Capacity Resources during Winter Storm Elliott-like or summer peak load conditions, additional operational testing will be beneficial to the early identification and correction of some mechanical issues that can help to bolster fleet performance during actual capacity emergencies.

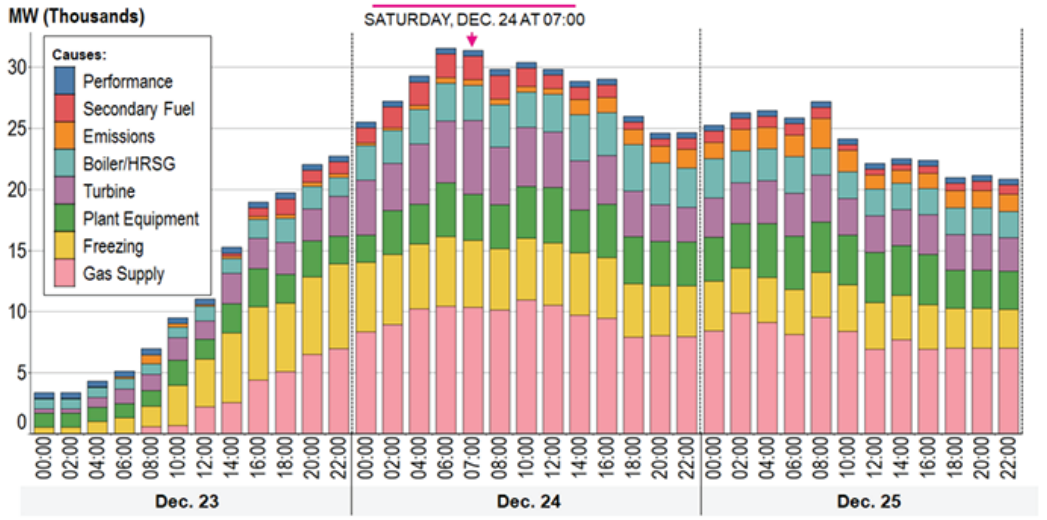
Winter Storm Elliott Forced Outages by Fuel Type



Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

Causes of Forced Outages to Gas Generators During Winter Storm Elliott



Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

30. As stated previously, the purpose of this test is to confirm that Generation Capacity Resources, especially those that have not operated recently, can do so upon PJM request and according to their operating parameters. The goal is to make sure Generation Capacity Resources can operate and given them an opportunity to demonstrate that rather than to assess penalties. However, should a resource continually fail in Generation Capacity Resource Operational Testing, it demonstrates the Generation Capacity Resource's inability to perform and must eventually result in some level of financial penalty.

31. The framework of the new Generation Capacity Resource Operational Testing process gives PJM the ability to request an operational test up to two times per Generation Capacity Resource, per summer or winter season, not including re-tests. The timing of such tests shall be at the discretion of PJM. This provides PJM an opportunity to test resources during the types of system conditions that, to the degree possible, are representative of those experienced during actual reliability events. A successful test for a Generation Capacity Resource demonstrates the following abilities:

    a. Start within the startup and notification time parameters submitted with the Generation Capacity Resource's applicable energy offer, plus the greater of 10 minutes or 10%, and

    b. Operate for the entirety of the minimum run time consistent with energy market offer.

32. During the testing period, the Generation Capacity Resource will be dispatched and settled the same as any other resource operating in the PJM energy market, including any uplift to allow the resource to recover its operating cost under PJM's existing uplift provisions. If the resource fails its test, regardless of whether that failure is due to a failure to start within the provided time or meet its minimum run time parameters, PJM can issue a re-test at a future time. The retest will be the same as the initial test except that the resource will not be eligible for any uplift payments to recover testing costs, and the retest will not be counted towards the two operational tests allowed per season. If the retest is also failed, regardless of the reason, PJM may issue another re-test at a future time, and continue doing so until the resource successfully passes the test. This allows PJM to continue re-testing resources that fail, without subjecting load to further uplift payments, which improves PJM's visibility of the operational capabilities of resources, and provides an incentive for generation owners to be accurate in the operating parameters submitted to PJM and used for scheduling.

33. Furthermore, for resources that entirely fail to start up and synchronize to the grid during a re-test, a Generation Capacity Resource Operational Test Failure Charge shall apply from the point at which the resource failed the re-test until it can successfully come online and operate. This is appropriate as the resource has demonstrated through multiple failed tests an inability to provide any capacity value during this time. The charge shall be assessed against the full daily committed UCAP MW of the resource and multiplied by the same Daily Deficiency Rate as used in the Generation Resource Rating Test Failure Charge.

34. It is my belief that the Generation Capacity Resource Operational Test will result in better operational performance of the generation fleet during capacity emergencies because it specifically creates an opportunity to test the operating capability of a resource prior to the event itself. This will help to identify any operational issues with a Generation Capacity Resource before an actual emergency condition arises. Furthermore, the operational test provides a check on the reported

availability of Generation Capacity Resources, which can improve the availability and outage metrics that feed into resource accreditation for future Delivery Years. This is particularly true for resources that are reported as available for extended periods of time, but rarely scheduled to operate, as these tests provide a check on that availability and can significantly increase the number of times that the ability of the resource to successfully start up and run when scheduled is tested each year.

Fixed Resource Requirement (FRR) Changes

35. PJM is proposing to make additional changes to the FRR option to create equitable treatment between FRR entities and RPM participants and equivalent standards and methods for resource adequacy risk modeling and accreditation. As such, the changes PJM proposes to the FRR option fall in the categories of:

    a. Resource Adequacy Risk Modeling and Accreditation,

    b. Performance Assessments Including Capacity Performance and Testing,

    c. Deficiency and Insufficiency Charges, or

    d. FRR Transition.

36. A brief summary of the changes in each area and the supporting rationale are provided in the following sections.

Risk Modeling and Accreditation Implementation in the FRR Option

37. PJM proposes to apply its new methods of resource adequacy risk modeling and accreditation to FRR entities. In short, the obligations of FRR entities and the accreditation of resources in the FRR Plans will be determined using the same methods of resource adequacy risk modeling and marginal accreditation as used for loads and suppliers participating in RPM Auctions. PJM's proposed methods for risk modeling and capacity accreditation present a significant enhancement over the existing processes. Uniform standards and calculations for the determination of resource adequacy risks and accredited capacity levels need to be done consistently across the PJM Region so that there are no gaps in how risks are assessed between RPM and FRR and that resource types are not accredited uniquely simply because of the business model they operate in. This portion of the proposal simply transposes the new risk modeling and accreditation proposal onto FRR entities and makes no further changes.

Performance Assessments Including Capacity Performance and Testing in the FRR Option

38. Under today's rules, FRR entities that demonstrate under-performance during a PAI have the option to elect a "physical assessment" in which they are obligated to carry additional capacity rather than the financial assessment that occurs for RPM entities. The "physical" option allows FRR entities with under-performing

resources the option to assign more capacity in the future rather than pay Non-Performance Charges for the under-performance. This form of a penalty, which defers the penalty's effects, can severely mute incentives to perform when the system needs it the most, especially when the FRR entity has excess supply not in its FRR Plan or can readily purchase it on the market at low cost. Removal of the "physical assessment" will expose FRR entities to the same financial incentives for performance as those with RPM commitments and thus create a uniform set of performance incentives across all capacity resources during a PAI.

39. Similar to the proposal for risk modeling and accreditation, PJM plans to apply the aforementioned reforms to Generation Capacity Resource testing and the associated Non-Performance Charges from failed tests to resource's committed in an FRR Plan as well. This change is beneficial as it would maintain uniform standards for testing across all Generation Capacity Resources.

Deficiency and Insufficiency Charge Enhancements

40. To create appropriate incentives for FRR entities to have sufficient megawatts of accredited capacity in place to meet their obligations, PJM proposes to adjust the level of the FRR deficiency and insufficiency charges from the current level of 1.2 * Base Residual Auction ("BRA") Clearing Price and 2 * Gross CONE, respectively, to the price-level corresponding to Point 1 on the Locational Deliverability Area ("LDA") Variable Resource Requirement (VRR) curve where the FRR obligation exists. This change makes equal the penalty to an FRR Entity for either not having adequate capacity in its initial FRR Plan when it is due (insufficiency charge), or, being short of capacity obligation during the Delivery Year (deficiency charge). This level provides sufficiently high incentives for FRR Entities to contract with resources in a timely manner to meet their obligations. Two times gross CONE for the insufficiency charge is higher than any point on the VRR Curve used in the RPM Auctions and may be inappropriately high and punitive. Conversely, for the deficiency charge at 1.2 times the BRA clearing price, low BRA clearing price levels, such as those recently observed (e.g., $34.13/MW-Day for the 2023/2024 Delivery Year) may be low enough that it is less expensive for an FRR Entity to pay the applicable charges instead of procuring sufficient capacity to meet the requirements of its plan. This is a bad outcome from a resource adequacy perspective and therefore needs to be addressed.

41. PJM selected the price-level of Point 1 on the applicable LDA VRR curve because the obligation of an FRR Entity is set based on the FPR which represents the amount of UCAP required to maintain the one-day-in-ten-years Loss of Load Expectation standard. Failure to meet that falls short of the target level of reliability and should correspond to a high penalty rate to incentivize curing the shortfall expeditiously. Additionally, the price associated with Point 1 on the applicable LDA VRR curve also generally corresponds to the maximum price level loads participating the in the BRA would pay if the RPM Auction cleared short of the reliability target. While they are not exact, using the price-level associated with Point 1 on the LDA VRR

curve is a reasonable proxy given that it is already an accepted anchor point on the VRR curves used in the BRA

42. For these reasons, it is reasonable for FRR entities to be subject to a similar economic signal to avoid being short of capacity in their FRR Plans.

FRR Transition

43. In recognition of the relatively longer lead times necessary for capacity planning in FRR regions, the significance of changes proposed in the filing, the relatively short timeframe in which such changes will be implemented, and the unique circumstances that FRR entities are in due to their inability to purchase capacity in an RPM Auction, PJM proposes a transition mechanism for FRR entities containing two elements:

    a. PJM proposes to allow a one-time option for FRR entities who have not yet met the minimum five-year commitment to the FRR election to re-join RPM beginning with the 2025/2026 BRA and carrying through the 2028/2029 BRA. Note that an election to re-join RPM during those years still requires a five-year minimum commitment period as applies under the current rules, meaning that entities will not be free to jump in and out of the market.

    b. For FRR entities remaining in the FRR option, PJM proposes to waive, for a four-year period, the insufficiency charge that applies when an FRR entity is unable to demonstrate at the time the initial FRR plan is due, that they have enough resources to meet their projected obligation. The waiving of this charge for the same period of Delivery Years simply allows FRR entities more time to meet their obligations without the assessment of an insufficiency charge.

44. The overall objective of this transition proposal is ultimately to procure all the resource adequacy needs of the entire PJM Region, either through RPM Auctions or through FRR Plans. FRR Entities concerned about being able to meet their obligation can re-join RPM, which would grant them access to sell their resources in RPM Auctions and purchase capacity from the pool. FRR Entities who remain in the FRR Alternative would be granted more time to procure or build Capacity Resources without being subject to insufficiency charges. This is appropriate given the magnitude of the changes and relatively quick implementation schedule. This is a reasonable transition proposal considering the unique circumstances that FRR entities are in.

45. This concludes my affidavit.

Document Accession #: 20231013-5157 Filed Date: 10/13/2023

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER24-___-000**

I, Adam Keech, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Adam Keech referred to in the foregoing document entitled "Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

/s/ Adam Keech
Adam Keech
Vice President of Market Design and Economics
PJM Interconnection, L.L.C.

Dated: October 13, 2023

Exhibit 6

Department of Energy

Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Undersecretary of Energy for Infrastructure

Exhibit 7

Department of Energy

Washington, DC 20585

Order No. 202-20-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.11(A) of Delegation Order No. 00-001.00G (Apr. 10, 2018), and re-delegated to the Assistant Secretary for Electricity on September 6, 2020, and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On September 6, 2020, the California Independent System Operator (CAISO), the Regional Transmission Organization whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

Since August, California has experienced several periods of extreme heat, some of which have resulted in rolling blackouts. On September 2, 2020, California Governor Gavin Newsom issued an emergency proclamation to help alleviate the stress on the state's power grid due to an "Extreme Heat Event." In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- "[B]eginning on September 2, 2020, a significant heat wave struck California, bringing widespread temperatures well in excess of 100 degrees throughout the State;"
- "[T]he National Weather Service [has] issued multiple Excessive Heat Warnings within [California];"
- "[T]he Extreme Heat Event has and will continue to put significant demand and strain on California's energy grid; and"
- "[T]he Extreme Heat Event is expected to last through at least September 7, 2020."

The proclamation authorizes emergency use of stationary generators, portable generators, and "auxiliary engines by ocean-going vessels berthed in California ports," and directs the state's Air Resources Board to "exercise maximum discretion to permit the use of stationary and portable generators or auxiliary ship engines to reduce the strain on the energy infrastructure and increase energy capacity." The proclamation also

suspends "[a]ny permit, regulation or law prohibiting, restricting or penalizing the use of stationary or portable generators or auxiliary ship engines" as allowed by the proclamation order.

On September 3, the CAISO issued a statewide flex alert for September 5-7, encouraging voluntary load reduction between 3:00 p.m. and 9:00 p.m. local time each day. The alert warns that consumers should "be prepared for potential power outages, both planned and unplanned during heat waves, especially in extremely high temperatures that last multiple days," noting that "[h]ot weather can also impact generation and transmission equipment, as it runs harder and longer with less time to cool, which can cause machinery failure." The alert explains that there is little energy available to import due to high heat predicted throughout the West, and that the wildfires in the state may take out transmission lines or cause lines to be shut down for the safety of firefighters in the area.

The CAISO notes that "[e]lectric demand forecasts have continued to increase since the issuance of the California Governor's emergency proclamation and the CAISO balancing authority area has lost additional generation supply because of wildfires." Application at 3. To address the situation, the "CAISO has started to direct all generators in its balancing authority area to produce to their maximum capability during certain times of the day," and has gone so far as to allow, when reliable and safe based on currently operating conditions, "certain generators to generate more than their interconnection capacity to provide additional power to the grid." *Id.* at 3. The impetus for the Application, however, arose on September 5, 2020, when the operator of the natural gas-fired resources identified in Exhibit A of the Application informed the CAISO that it could not produce to its maximum generation capability without exceeding its federal air quality or other permit limitations. *Id.* "The CAISO is informed and believes these limitations involve both permit limitations under federal law for nitrogen oxide emissions and ammonia releases as well as a limitations regarding fuel and ammonia throughput." *Id*.

The CAISO requests "that the Secretary issue an order immediately, effective September 6, 2020, authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id.* at 1. The generating units specified are units 1 - 5 at the Walnut Creek Energy Park in the City of Industry, California; units 5/6 and 7/8 at the El Segundo Energy Center in El Segundo, California; and units 1 - 4 at the Long Beach Generating Station located in Long Beach, California. *Id.* For purposes of this Order, these units are referred to as the "Specified Resources." Collectively, they represent up to as much as 100 MW. The CAISO requests "such order be entered today, September 6, 2020, and remain effective for a period of seven (7) days, without prejudice to the possible issuance of further orders as necessary to address the emergency…[to] ensure additional supply is

available during a period in which California may continue to experience extreme weather and wildfires that have forced generation out of service." *Id*. at 2.

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act and notes that the Specified Resources are located in different communities within California and should not result in any disproportionate impact on a single community. *Id.* at 4. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 6, 2020, to September 13, 2020, in the event that the CAISO determines that generation from the Specified Resources is necessary to meet the exceptional levels of electricity demand that the CAISO anticipates in California, I direct the CAISO to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in California between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time on days when the demand on the CAISO system exceeds expected energy and reserve requirements.

B. The CAISO shall select the combination of units that meets the reliability emergency and minimizes environmental impact. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources.

C. By September 21, 2020, the CAISO shall report all dates between September 6, 2020, and September 13, 2020, on which the Specified Resources were

operated, the hours of operation, and the estimated air emissions (including nitrogen oxides and ammonia releases) and fuel and ammonia throughput associated with operating each unit. The CAISO shall submit a final report by October 13, 2020, with any revisions to the information reported on September 21.

D. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 13, 2020, with the exception of the reporting requirements in paragraph C. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. this 6th day of September, 2020.

_____

Bruce Walker
Assistant Secretary for Electricity

Exhibit 8

Maintaining the PJM Region's Robust Reserve Margins

A Critique of the PJM Report:
Energy Transition in PJM: Resource Retirements, Replacements and Risks

May 2023

Prepared by
James F. Wilson
WILSON ENERGY ECONOMICS

Prepared for
Sierra Club and Natural Resources Defense Council

Contents

I. Executive Summary

PJM Interconnection, LLC ("PJM") is the regional transmission organization ("RTO") that coordinates wholesale electricity markets in the Mid-Atlantic area ("PJM Region"). PJM has embarked on a multiyear effort to study the potential impacts associated with the evolving electric generation resource mix in the transition to cleaner forms of energy in the PJM region, resulting in a series of "Energy Transition in PJM" reports.[1] PJM's goal with this analysis has been to identify gaps and opportunities in PJM's current wholesale market constructs and offer insights into the future of market design, transmission planning and system operations.[2] The first two reports in this series presented scenarios of the changing resource mix out to 2050, identified generator operational characteristics that will be needed to reliably operate the future system, and called attention to the need to accurately assess the reliability contributions of all resource types, among other emerging issues.

The first two reports in PJM's Energy Transition in PJM series did not raise concerns or even discuss PJM Region "reserve margins" (the total amount of capacity to meet customers' peak loads reliably). However, PJM's recent, third report, *Energy Transition in PJM: Resource Retirements, Replacements and Risks*[3] ("R4 Report"), focuses on reserve margin calculations for 2023 to 2030. Despite a history of high reserve margins, the R4 Report's scenarios suggest that the region could face drastically low reserve margins, jeopardizing resource adequacy and reliability, in the transition to clean energy between now and 2030. The R4 Report anticipates low reserve margins based on "balance sheet" calculations that simultaneously assume strong load growth, a fast pace of retirements, and a slow pace of new entry.[4]

This paper reviews and critiques the R4 Report's resource adequacy calculations. I conclude that PJM's simple balance sheet calculations are invalid, as they combine highly contradictory assumptions that cannot occur together. The calculations ignore the simple reality, repeatedly demonstrated over the history of PJM's energy and capacity markets, that the pace of retirements and new entry are interconnected through the price signals of PJM's "RPM" capacity market and other markets, and consistently result in procuring more than enough capacity to maintain reliability. Whenever reserve margins decline, RPM prices rise, and the market soon responds with some combination of additional entry and delayed retirements, returning the system to higher reserve margins and moderate capacity prices. The capacity market has consistently and effectively procured more than sufficient capacity, as PJM has repeatedly concluded in its reports on RPM auction results.[5]

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[1] PJM, *Energy Transition in PJM: Frameworks for Analysis,* December 2021, available here; *Addendum*, available here; *Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid*, May 2022, available here; *Addendum*, available here.

[2] See, for instance, *Energy Transition in PJM: Frameworks for Analysis,* p. 1.

[3] PJM, *Energy Transition in PJM: Resource Retirements, Replacements and Risks*, February 2023, ("R4 Report"), available here. The R4 Report was discussed with stakeholders at a special workshop on March 28, 2023; PJM's presentation at that meeting is available here. PJM also published a Frequently Asked Questions document on April 21, 2023 ("R4 Report FAQ"), available here.

[4] See, for instance, R4 Report page 16, presenting scenarios under which reserve margins fall to 7% or 8% by 2028 and "may be insufficient to cover peak demand expectations" even with demand response.

[5] See, for instance, PJM new release February 27, 2023, *PJM Capacity Auction Procures Adequate Resources*, p. 1 (quoting CEO Manu Asthana: "The capacity auction continues to be our best tool to ensure reliability at competitive prices in PJM").

If anything, the RPM capacity market is overly conservative. Reserve margins have chronically been excessive, as will be shown later in this paper. Reserve margins need to decline toward the target levels needed for adequate reliability, and likely will in the coming years. And PJM has additional tools at its disposal, ignored in the R4 Report, to help keep reserve margins at acceptable levels (such procurement through the RPM "incremental" auctions,[6] and the "reliability backstop" provisions.[7]) Based on the invalid calculations presented in the R4 Report, PJM has needlessly worried stakeholders and policy makers with drastically low reserve margin scenarios that are highly unrealistic, as I will further explain in this paper.

The R4 Report briefly acknowledges the important challenges associated with the anticipated changes in the resource mix,[8] and that PJM and stakeholders are working to address them.[9] The Winter Storm Elliott experience in December 2022 suggests the urgency of efforts to bolster plant performance under extreme cold, fuel security, and winter resource adequacy.[10] The unrealistic scenarios in the R4 Report suggesting very low reserve margins draw attention away from the important issues around winter resource adequacy and the changing resource mix, and could lend support to unnecessary and misguided policies aimed at retaining high-cost, high-emission power plants,[11] contrary to federal and state policies that seek to require low- or no-emission generation.

The remainder of this paper is organized as follows. The next section explains how PJM's RPM capacity construct creates price signals that have effectively guided retirement and new entry decisions over many years. Sections III and IV provide a critique of the R4 Report's balance sheet calculations and assumptions. The final section explains why it is important for resource adequacy analysis to be realistic.

[6] RPM incremental auctions are held closer to the delivery year and afford PJM an opportunity to acquire additional capacity. See PJM Tariff Attachment DD Section 5.4.

[7] PJM Tariff Attachment DD Section 16, *Reliability Backstop* (providing that if RPM clears more than one percent below the target reserve margin PJM will investigate the causes and recommend corrective actions; and if this occurs for three consecutive delivery years PJM can hold a Reliability Backstop Auction to procure additional capacity).

[8] R4 Report p. 17 ("The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain the reliability of the bulk electric system.")

[9] R4 Report p. 17 ("Managing the energy transition through collaborative efforts of PJM stakeholders, state and federal agencies, and consumers will ensure PJM has the tools and resources to maintain reliability.")

[10] PJM's preliminary analysis of the Winter Storm Elliott event with substantial supporting information is available here. PJM expects to provide "lessons learned" from the event in May 2023 with a full report in July 2023.

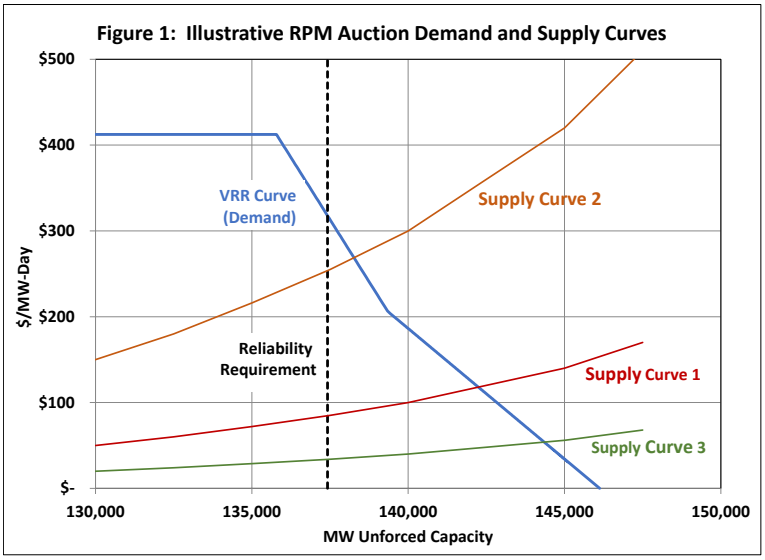
[11] As one recent example, see the *Commission Order* in West Virginia Public Service Commission Case No. 22-0793-E-ENEC, April 24, 2023, available here, pp. 7-9 ("Moreover, suggestions by some intervenors that there are no existing or expected reliability problems in PJM have recently been rejected by PJM. [*footnote citing to R4 Report*] In fact, PJM has recently studied the reliability quality of its near-term power supply and found that reliability is impacted by over-reliance on intermittent resources, mostly solar and wind... In addition to reserve margins that are far below the historical margins in PJM, the PJM Report 2023, shows that by 2026 all of the capacity reserves in PJM will be intermittent resources or voluntary customer curtailments, neither of which can be dispatched when needed as is the case with thermal generation resources.") citing the R4 Report, in support of a proposal to subsidize a coal-fired plant to keep it in operation one additional year, from June 1, 2023 to May 31, 2024).

II. Resource Adequacy, Reserve Margins and Capacity Prices in the PJM Region

One of PJM's core goals is to ensure that its wholesale markets will provide adequate total electric generating capacity to meet customer peak loads plus a "reserve margin," to account for plant outages and other uncertainties. PJM's wholesale energy and ancillary services markets, and related bilateral markets, are the main sources of revenue for generation on the PJM system, while PJM's Reliability Pricing Model ("RPM") capacity construct is intended to provide the additional, "missing money" needed to achieve resource adequacy targets.[12] Thus, RPM plays a pivotal role in ensuring resource adequacy; the R4 Report completely ignores this in its balance sheet calculations.

Under RPM, PJM holds annual auctions to acquire capacity commitments for the "delivery year" three years into the future (for example, the RPM auction held in May 2018 acquired commitments for the period from June 1, 2021 through May 31, 2022).[13] The RPM auctions use a sloped "demand curve" for capacity that is positioned based on PJM's forecast of future peak load plus the target reserve margin, and the capacity price that is considered needed to attract the construction of new power plants (this price parameter is called "Net CONE"). The capacity "supply curve" for each auction is based on price offers from the owners of eligible power plants and providers of demand response and energy efficiency resources. In the RPM auctions, the intersection of the sloped demand curve and the supply curve determines the capacity price, cleared quantity, and reserve margin for the future delivery year.[14] This is illustrated in Figure 1, in which "Supply Curve 1," shown in red, clears at about $120/MW-day.

Figure 1: Illustrative RPM Auction Demand and Supply Curves

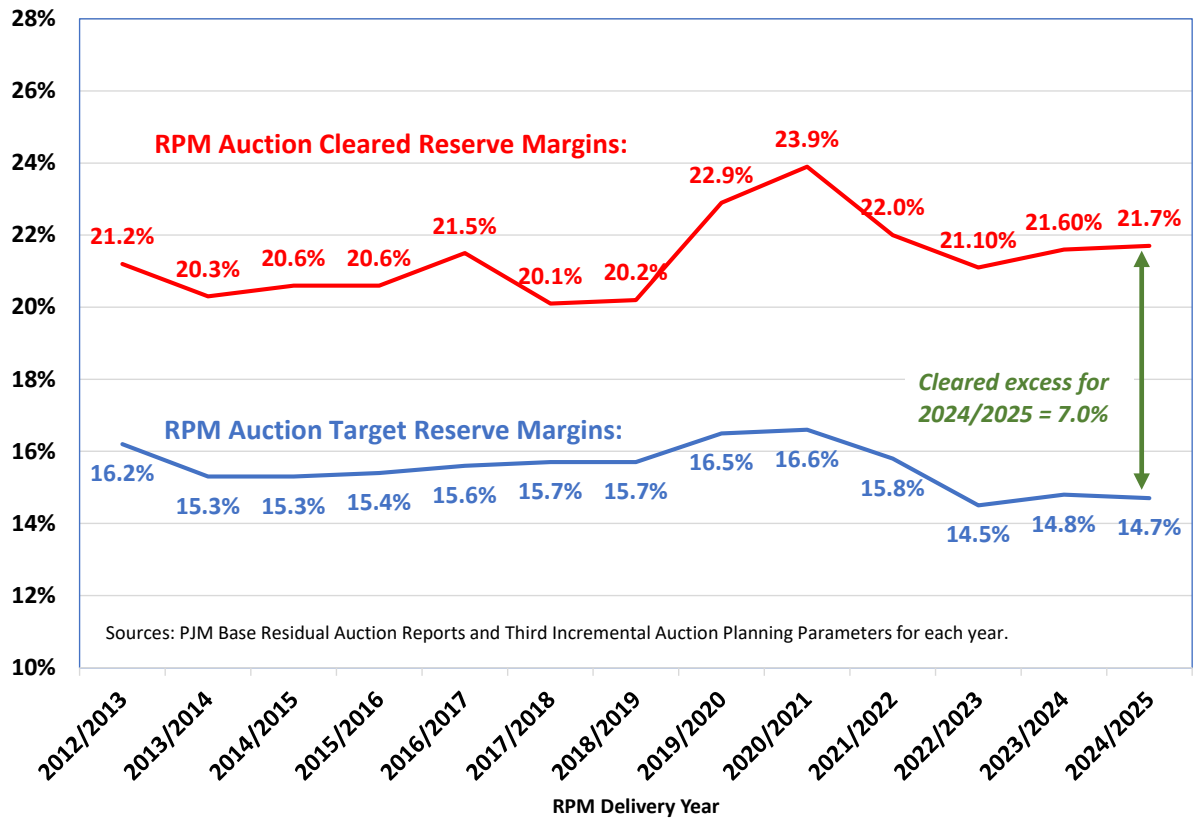


The sloped RPM demand curve results in clearing prices that signal whether additional capacity is needed on the PJM system. When capacity is relatively scarce or expensive (shifting the supply curve up and left; Supply Curve 2 in Figure 1), the sloped demand curve ensures that the auction will clear at a higher price, creating a price signal and incentive for market participants to delay retirements, upgrade existing plants, build new plants, and develop demand response. At times when capacity is abundant and low cost (shifting the supply curve down and right; Supply Curve 3 in Figure 1), as has been the case recently, the sloped demand curve results in RPM clearing more capacity and at a lower clearing price, which reduces incentives for new plants and encourages high-cost existing plants to retire.

[12] For a more extensive discussion of the importance of energy and ancillary services markets and the different roles of these markets and the capacity market see Wilson, James F., *"Missing Money" Revisited: Evolution of PJM's RPM Capacity Construct*, prepared for the American Public Power Association, September 2016, available here.

The RPM mechanism has worked in the past to maintain reserve margins at high levels. Figure 2 shows that while the target installed reserve margins for the RTO Region have generally been around 15% or 16% of the forecast peak load (the blue line in Figure 2), the RPM auctions have regularly cleared significantly more – reserve margins of 20% or more (red line). So while the target reserve margins of about 15% or 16% of peak load represent the capacity PJM believes it needs to reliably operate the system, RPM has consistently drawn commitments that are far in excess of these targets. Note that the actual reserve margins and excess capacity in the delivery year have been even larger, because the final load forecast and actual, weather-normalized peak loads are generally lower, and because thousands of MW of additional resources that fail to clear in each RPM auction nevertheless continue to operate as "energy-only" resources on the PJM system.

Figure 2: RPM Base Residual Auction Target and Cleared Reserve Margins



In a 2020 report, I explained that this over-procurement is a result of RPM auction design features and inaccurate peak load forecasts.[15] I also explained that the excessive capacity commitments and reserve

[13] Recent and upcoming auctions are less than three years forward due to delays that have occurred for various reasons. PJM intends to return to a three year forward schedule in a few years.

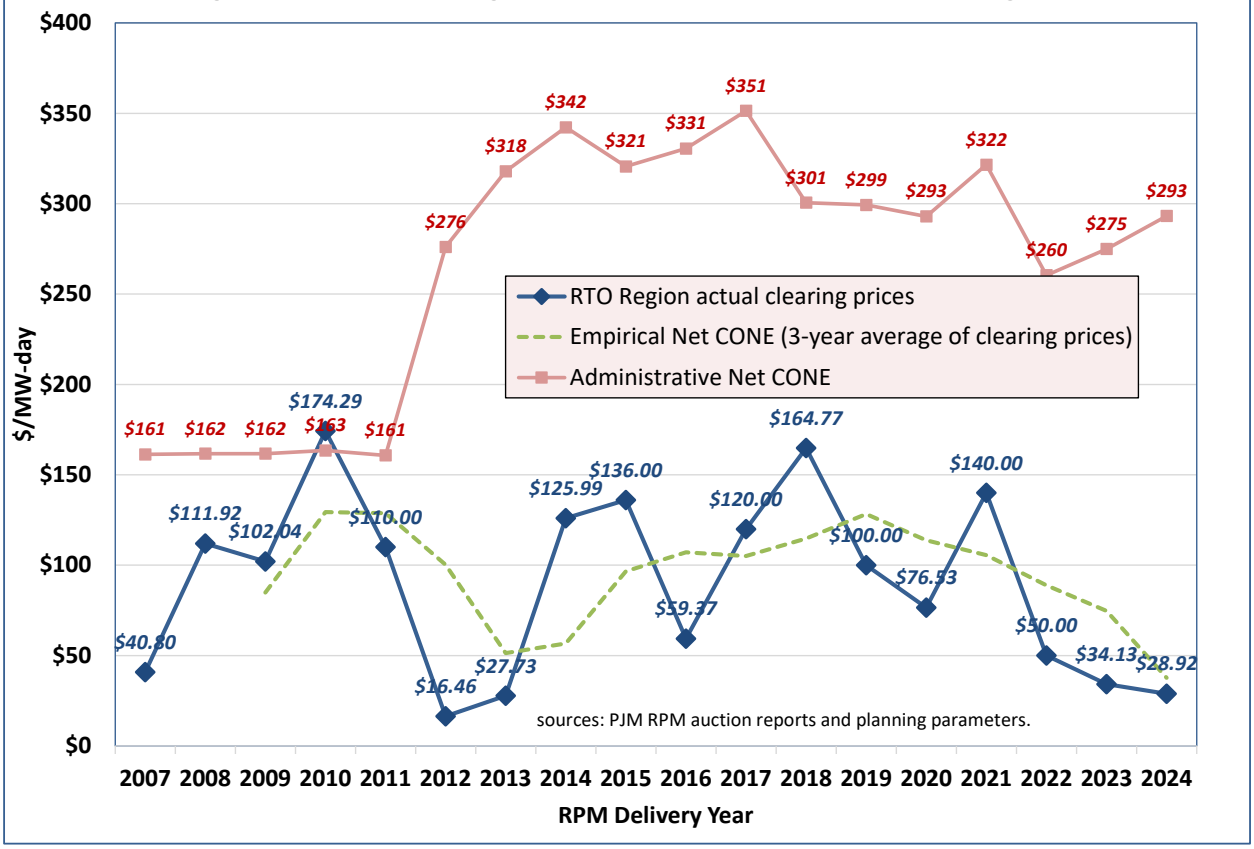
[14] The actual delivery year reserve margins can be somewhat different (usually higher) due to updated load forecasts and adjustments to capacity commitments through additional, "incremental" RPM auctions.

[15] Wilson, James F., *Over-Procurement of Generating Capacity in PJM: Causes and Consequences*, February 2020, prepared for Sierra Club and Natural Resources Defense Council ("Over-Procurement Report"), available here.

margins harm consumers and markets.[16] The over-procurement and excessive reserve margins have continued to the present, with the most recent RPM auction providing a 21.7% reserve margin for the 2024-2025 delivery year, far above the target of 14.7% for adequate reliability.[17]

As noted above, RPM auction reserve margins are linked to RPM capacity prices through the sloped demand curve used in the auctions; high reserve margins go with low capacity prices, and low reserve margins lead to high capacity prices. Figure 3 shows the history of RPM capacity prices for the RTO Region (blue line). Consistent with the high reserve margins shown in Figure 2, capacity prices have generally been rather low, and far below the administrative Net CONE values (shown in red in Figure 3) that are supposed to represent the prices needed to attract new entry.

Figure 3: RPM Clearing Prices and Net CONE Values (RTO Region)



The RPM mechanism has worked to maintain high reserve margins despite various stresses that have arisen from time to time. As an example of the mechanism at work, the PJM Region experienced a wave of retirements in the 2012 to 2015 time frame, largely driven by emissions regulations, when close to 22,000 MW retired.[18] Despite these retirements, PJM reserve margins remained high (as shown in Figure 2), primarily due to the construction of a similar quantity of new gas-fired power plants in the PJM region

[16] Over-Procurement Report, pp. 10-13.

[17] PJM, *2024/2025 RPM Base Residual Auction Results*, available here (stating at p. 2 that the RPM auction result represents a 21.7% reserve margin for the PJM region, compared to the resource adequacy target of 14.7%).

[18] R4 Report p. 6.

at about the same time.[19] The market functioned as intended, encouraging new, more efficient plants to replace older, uneconomic ones.

Figure 3 also shows that following RPM auctions that result in relatively high prices, the auction price has always declined sharply the following year, suggesting that market participants react quickly to RPM price signals (and also to changes in RPM demand, and to changes in energy price expectations), increasing supply to bring prices back to moderate levels. RPM prices for the RTO Region have risen above $130/MW-day four times in the eighteen years shown in Figure 3 (in 2010, 2015, 2018, 2021), and in each instance the price fell by over $60/MW-day the following auction, to an average of $80/MW-day. This dynamic has resulted in capacity prices that have been relatively stable on three-year-average basis, as shown in Figure 3 (green dashed line), and reserve margins that have been well above targets, as shown in Figure 2. RPM has been shown over eighteen years to be quite robust and resilient.

It is worth noting that for RPM to clear near the target reserve margin, the capacity price would have to rise to over $300/MW-day on the sloped demand curve, roughly ten times recent clearing prices.[20] This huge increase in the capacity price would serve as a very strong incentive for relatively more new entry and for delay of retirement plans, despite the reserve margin being near the target.

Figures 2 and 3 show that RPM has consistently cleared very high reserve margins at prices well below Net CONE, including in the most recent auction held in February 2023 for the 2024/2025 delivery year. The causes of over-procurement, discussed in my 2020 report, have only partially been corrected at this time.[21] Thus, it is important to keep in mind going forward that if reserve margins decline toward target levels, raising capacity prices, this will bring the results closer to the desired procurement, which will be beneficial to consumers and the markets. The R4 Report worries that "For the first time in recent history, PJM could face decreasing reserve margins…";[22] if so, this would represent a needed correction rather than present a cause for concern.

Looking forward, there will be more retirements, perhaps even the R4 Report's estimate of 40 Gigawatts ("GW") through 2030,[23] as federal and state policies encourage moving away from high-cost and high-emitting resources. However, PJM's generation interconnection queues reflect a far greater quantity of potential new resources: over 17 GW of natural gas-fired resources, and over 200 GW of renewable and renewable-storage hybrid resources.[24] The changing resource mix in PJM, as in other regions across North America and around the world, will necessitate changes to market mechanisms and planning methods to accommodate the new resources while maintaining reliable operations, as the earlier reports in the

[19] This same observation (that the retirements during this period were matched by new entry) was made by PJM in its October 18, 2022 report in response to questions posed by the Federal Energy Regulatory Commission in FERC Docket No. AD21-10, *Modernizing Wholesale Electricity Market Design*, p. 38.

[20] See, for instance, PJM, *Planning Period Parameters for the 2024-2025 Base Residual Auction*, available here.

[21] Over-Procurement Report pp. 4-10; see also Wilson, James F., *Affidavit in Support of the Comments of the Public Interest Entities*, filed October 21, 2022 in FERC Docket No. ER-22-2984 (RPM Quadrennial Review), pp. 7-15.

[22] R4 Report p. 17.

[23] R4 Report p. 17.

[24] R4 Report p. 2.

Energy Transition in PJM series discussed. The final section of this paper identifies the PJM stakeholder processes that are addressing these challenges.

III. Critique of the R4 Report's "Balance Sheet" Reserve Margin Calculations

In this context of a long history of over-procurement, high reserve margins, and moderate capacity prices, PJM released its R4 Report with "balance sheet" resource adequacy calculations to 2030. Balance sheet calculations are common in the Integrated Resource Plan filings of vertically integrated utilities, where they are typically used to show the amount of additional capacity that the utility, as the sole or central planner of capacity for its service territory, must build or acquire to keep reserve margins at target levels. Balance sheet calculations will typically show the capacity the utility expects to have available over the coming years (reflecting current resources, retirements, and new additions), and its demand for capacity (based on a peak load forecast net of demand-side resources). Comparing the projected available capacity before additions to the projected demand for capacity results in projected reserve margins; Table 1 provides an example. Utilities may also apply the balance sheet method to evaluate scenarios of higher demand or fewer resources in order to identify when capacity additions may be needed. Thus, balance sheet calculations can be a useful communication tool under circumstances where a single entity is responsible for planning the future capacity balance.

Table 1: Example of "Balance Sheet" Reserve Margin Calculations
(Table 8 From Oklahoma Gas & Electric's 2021 Integrated Resource Plan)

Table 8 – Planning Reserve Margin (MW unless noted)

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capacity	Owned Capacity	6,702	6,534	6,534	6,323	6,259	5,856	5,856	5,856	5,856	5,371
	Purchase Contracts	47	47	47	47	47	47	47	47	47	16
	Total Capacity	6,749	6,581	6,581	6,370	6,306	5,903	5,903	5,903	5,903	5,386
Demand	Demand Forecast	6,303	6,313	6,379	6,431	6,491	6,543	6,589	6,626	6,630	6,659
	OG&E DSM	278	309	340	372	403	432	456	477	494	505
	Net Demand	6,025	6,004	6,039	6,059	6,088	6,111	6,133	6,149	6,136	6,154
Margin	Reserve Margin[12]	12%	10%	9%	5%	4%	-3%	-4%	-4%	-4%	-13%
Needs	Needed Capacity	0	145	183	417	514	942	967	985	970	1,507

The R4 Report refers to the application of a balance sheet approach in multiple places,[25] however, the balance sheet calculations were not provided, only the reserve margin results (R4 Report Table 1, reproduced here).[26] The reserve margin results were provided for the R4 Report's two new entry scenarios and two load forecast scenarios. Referring to the reserve margin calculations, the R4 Report states (pp. 16-17), "By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%... For the first time in recent history, PJM could face decreasing reserve margins, as shown in Table 1, should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue."

[25] R4 Report pp. 2, 3, 4, 17.

[26] R4 Report FAQ #2 ("A data annex will not be provided given market-sensitive and licensing issues related to the content of the study.")

The fundamental and fatal flaw in PJM's balance sheet calculations is the simple fact that it ignores how PJM has designed its own wholesale markets, and in particular its RPM capacity market, to work. The projected lower reserve margins cannot occur without causing much higher capacity prices (as explained in the prior section, due to the sloped RPM demand curve). Higher capacity prices lead to slower retirements, faster new entry and higher reserve margins. The R4 Report makes calculations using projections of retirements, new entry, reserve margins and capacity prices that are contradictory in the context of PJM's RPM and other wholesale markets; as a result, the results presented in the R4 Report are not plausible or possible.[27]

Table 2: The R4 Report's Table 1 "Balance Sheet" Results (page 16)

Table 1. Reserve Margin Projections Under Study Scenarios

Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

Table 3 provides estimates of the RPM capacity prices that would result from the balance sheet reserve margins presented in Table 1 of the R4 Report shown above.[28] Under PJM's Low New Entry scenario that is projected to lead to an unprecedented[29] 15% reserve margin for the 2026 delivery year, the RPM clearing price would have to rise to approximately $338/MW-day, or ten times the prices in recent auctions. Even under the High New Entry scenario, the projected reserve margins correspond to much higher capacity prices in 2026 and beyond, which would stimulate additional new entry and delay of retirements.

The R4 Report assumed capacity prices would remain at recent low levels[30] even while reserve margins decline due to the fast pace of retirements and slow pace of new entry. These assumptions – a fast pace of retirements, a slow pace of new entry, low reserve margins and low capacity prices – are simply contradictory and ignore the basic market dynamic that ensures resource adequacy in the PJM region.

[27] R4 Report FAQ #22 acknowledges this flaw ("Does this report consider the price-signaling function of the capacity market? This study did not intend to forecast future capacity prices and its retention of existing capacity in the 2025–2030 time period as capacity margins are forecast to tighten.")

[28] The estimated RTO Region capacity prices shown in Table 3 are based on the corresponding reserve margins in the R4 Report's Table 1, the applicable RPM base residual auction demand curve shapes for future years (the shape changes in 2026-2027 as a result of the recent Quadrennial Review) and Net CONE set to $250/MW-day.

[29] The lowest RTO Region reserve margin resulting from an RPM base residual auction was 16.5% in 2010/2011. This was based upon a load forecast that was later substantially lowered, leading to a higher delivery year reserve margin. Since 2012/2013 all base residual auction reserve margins have been 20% or higher, as shown in Figure 1.

[30] R4 Report p. 10.

Lower reserve margins cannot occur without the much higher capacity prices that would lead to delays in retirements and a faster pace of new entry.[31]

Table 3: Capacity Prices Corresponding to The R4 Report's Reserve Margin Projections

$/MW-day	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	$34.13	$28.92	**$179**	**$338**	**$438**	**$438**	**$438**	**$438**
Electrification	$34.13	$28.92	**$235**	**$438**	**$438**	**$438**	**$438**	**$438**
High New Entry								
2023 Load Forecast	$34.13	$28.92	**$56**	**$64**	**$173**	**$251**	**$173**	**$338**
Electrification	$34.13	$28.92	**$87**	**$118**	**$338**	**$424**	**$424**	**$438**

Note: For 2023 and 2024, RTO Region prices from the applicable RPM base residual auctions are shown; for 2025 to 2030, the capacity prices were estimated based the corresponding reserve margins in the R4 Report's Table 1, the applicable RPM base residual auction demand curve shapes for future years (the shape changes in 2026-2027 as a result of the recent Quadrennial Review) and Net CONE set to $250/MW-day.

The R4 Report's reserve margin scenarios are unrealistic for additional reasons. Market participants are continually assessing all of PJM's markets and the potential need for resources, and planning retirements and new entry accordingly.[32] Whatever the capacity price might be, a decline in the reserve margin would also lead to expectations of relatively less supply and higher prices in forward energy markets, raising expectations for future revenue opportunities and encouraging market participants to retain existing resources and plan new ones.

IV. Critique of the R4 Report's Retirement, New Entry, and Peak Load Projections

While the fundamental flaw in the R4 Report's calculations is the neglect of market dynamics and use of contradictory assumptions, this section of the paper also comments on the details of the retirement, new entry, and load forecast projections. These projections are highly conservative; that is, they reflect a fast pace of retirements, a slow pace of new entry, and increases in peak loads that are highly speculative.

1. The Assumed Fast Pace of Retirements Could Occur Only if Reserve Margins Remain High

The R4 Report estimated annual retirements to 2030 based on a combination of various federal and state policies and also "economics" (estimated profitability based on energy and capacity price assumptions).[33] Much of the older and less efficient capacity on the PJM system retired over the 2012 to 2022 period; a

[31] PJM's own consultant, The Brattle Group, has made this point very clearly on various occasions. See, for instance, *Written Testimony of Dr. Kathleen Spees and Dr. Samuel Newell, Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market,* filed August 20, 2021 in FERC Docket No. ER21-2582, pp. 19-20 Section C.3 ("Capacity Markets with Sloped Demand Curves Cannot Simultaneously Produce Low Prices and Poor Resource Adequacy.")

[32] For a more extensive discussion of the evidence that market participants are reacting to market conditions see, for instance, Wilson, James F., *Affidavit in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates*, filed May 7, 2018 in FERC Docket No. ER18-1314, pp. 11-16.

[33] R4 Report pp. 5-10.

total of 47.2 GW, according to the R4 Report.[34] The R4 Report generally assumes the remaining plants considered at risk of retirement will be rather quick to choose retirement, with an additional 40 GW retiring over 2022 to 2030.[35] This is similar to the pace of retirements over the 2012 to 2022 period.

The R4 Report identifies retirement dates as driven by policy, economics, or a combination of policy and economics, with 10 GW in the last category. In the workshop to discuss the report, PJM staff acknowledged that the R4 Report's analysis generally assumed retirements would occur at the earliest dates suggested by policy or economics, while for many of the resources there is some flexibility for the retirements to occur later, especially if reliability is jeopardized.[36] The R4 Report also did not consider that in many instances the owners could keep the capacity in operation through fuel switching or additional environmental investments.

As an example of the R4 Report's conservative assumptions, the R4 Report assumes 4.4 GW of retirements in 2026 associated with the U.S. Environmental Protection Agency's Good Neighbor Plan, which limits emissions of nitrogen oxides from facilities in certain states to protect against harmful ozone pollution in downwind states.[37] Reducing these emissions typically involves the installation of well-established selective catalytic reduction technology. While the Good Neighbor Plan involves emission-trading programs to increase flexibility for the regulated industry, the R4 Report assumed that every electric generating facility that would face costs under the rule would retire. The report noted that EPA would finalize this rule on March 15, 2023; in fact, EPA's analysis accompanying the final rule finds that only 1.4 GW of generation in PJM would retire, on net, as a result of the rule; [38] and PJM acknowledges that the final rule moves the retirement date to 2030.[39] While PJM couldn't know the details of a forthcoming rulemaking, its overly conservative approach of assuming that every unit facing costs under the rule would retire, *and* its failure to timely update its report after publication of EPA's rule, contribute to an overall inaccurate picture of how the PJM generation fleet is likely to change over the coming decade.

The low prices in the last three RPM base residual auctions – $50.00, $34.13, and $28.92/MW-day for the RTO Region – to some extent result from recent substantial increases in energy prices and price expectations;[40] higher energy prices lead to lower needs for capacity revenue. However, the low capacity prices also show that the owners of existing capacity are not in a hurry to retire their resources.

[34] R4 Report p. 6.

[35] R4 Report p. 2.

[36] See, for instance, R4 Report FAQ #11, acknowledging that many of the policies studied in the report have "safety valve" provisions that would enable plants to operate additional years for reliability purposes.

[37] R4 Report page 7.

[38] U.S. Environmental Protection Agency, Resource Adequacy and Reliability Analysis, Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards at Table. C4 (Mar. 2023), available here (showing 1.9 GW of coal retirements incremental to the base case in 2030, offset by fewer retirements among nuclear and other steam resources).

[39] R4 Report FAQ #12 (acknowledging that the final Good Neighbor Rule "moves the estimated retirement date of 4.400 MW from 2026 to 2030.")

[40] While peak period energy prices in PJM West have averaged well under $50/MWh for many years, forward prices are now over $60/MWh for 2025 through 2028.

Throughout the entire history of RPM we have repeatedly seen owners continue to operate even uneconomic resources, and even when the resources fail to clear in RPM and earn capacity revenue.

In addition to the large amount of capacity willing to accept quite low capacity prices, there has been over 9,000 MW of additional generation that offered but failed to clear in the auction in each of the last eleven RPM base residual auctions, and over 18,000 MW of uncleared generation in four of the last six auctions.[41] Much of this uncleared capacity does not retire. PJM's sensitivity analysis of the results of the most recent auction (for 2024-2025, which cleared at $28.92/MW-day) shows that removing 6,000 MW of low-cost supply from the supply curve for the RTO region would have reduced the total cleared quantity in the auction by less than 900 MW, and it would have raised the clearing price only to $56.26/MW-day; that is, a large amount of the uncleared capacity in the auction was also willing to accept quite low capacity prices.[42] While the pace of retirements may increase and reduce the current capacity overhang, this tendency for many owners to prefer to hold on for additional years if they have the flexibility to do so is unlikely to fundamentally change. Continued operation may entail losses, but once the retirement process is begun it is hard to reverse, and there is always hope that market conditions will improve.

It is also worth noting that with each announced retirement, the owners of other marginally economic plants will update their models to reflect the absence of the retiring plant, which will raise their expectations of energy and capacity prices and profits and make holding on another year more attractive. Developers of new plants will also update their models when a retirement is announced, which may lead them to accelerate their plans. Each announced retirement contributes to other marginal plants possibly holding on longer, and new projects possibly arriving sooner.

In addition, when a large plant retires, it leaves behind a local transmission system capable of delivering generation at that location to loads. New generation at or near the site can take advantage of the existing transmission capacity, which can both speed interconnection and lower its cost. The R4 Report's pessimistic retirement and new entry projections do not recognize this interaction, so this is an additional way the R4 Report's assumptions are both pessimistic and contradictory.

Note also that to the extent retirements are driven by state or federal policies, these policies are typically in place years in advance of the specified deadlines, so the market has plenty of time to anticipate the reduction in capacity and to plan replacements. This dynamic was seen in the wave of retirements over 2012-2015 that was matched with new entry and did not lead to declining reserve margins, as noted above. The EPA Good Neighbor policy and the Illinois Climate and Equitable Jobs Act contain 2030 deadlines, allowing plenty of time for the market to anticipate the reductions and plan replacements.

So while perhaps the rapid pace of retirements reflected in the R4 Report's retirement scenario could happen, the rapid pace would only occur in an environment of low capacity prices. But capacity prices can remain low only if reserve margins remain high, due to some combination of slow load growth and ample new entry. Accordingly, the R4 Report's retirements scenario either won't occur, or will occur with adequate reserve margins, contrary to the R4 Report's Table 1.

[41] PJM, 2024-*2025 RPM Base Residual Auction Report*, Table 6, available here.

[42] PJM, *Scenario Analysis for Base Residual Auction*, Scenario # 4 (remove 6,000 MW of supply from bottom of supply curve in region outside of MAAC), available here.

2. The Assumed Slow Pace of New Entry Could Occur Only if Reserve Margins Remain High

The R4 Report notes the enormous amount of capacity currently in PJM's interconnection queues – 290 GW – but estimated that only a tiny fraction of this capacity will actually be built, applying "commercial probabilities" of projects coming into service based on historical data.[43] Renewable capacity was further adjusted to reflect its resource adequacy value.[44] While there is presently 270 GW of renewable capacity in the queue, this was reduced to 13.2 GW of new capacity by 2030, and only 6.7 GW in capacity value terms.[45] Of the 17.6 GW of natural gas projects in the queue, of which 12 GW already have signed Interconnection Service Agreements, the R4 Report assumed only 3.8 GW would be built.[46] The R4 Report states that these pessimistic assumptions were "augmented" based on scenarios from S&P Global's North American Power Outlook, and additional capacity was added, however, no details were provided about how the assumed total quantity of new entry was determined.[47] It is unclear to what extent the Low and High New Entry Scenarios presented in the R4 Report reflect the low historical commercial probabilities of renewable resources or take into account the improving economics of such resources.[48]

The low historical commercial probabilities are based on a period of chronic over-forecasting of load, chronic high reserve margins, and low need for new entry. In the past, developers added projects to the interconnection queue only to see the need for the capacity evaporate as the load forecast was lowered and RPM cleared very high reserve margins. The R4 Report also assumed Demand Response (capacity provided by demand-side resources) would remain at current levels, despite its projection of declining reserve margins.[49] Were reserve margins to decline at all, the rate of project completions would very likely rise considerably, and additional demand response would develop. PJM's assumed very low rate of completion of renewable resources in the queue, especially under its Low New Entry scenario, also ignores the strong incentives put in place last year with the Inflation Reduction Act.[50]

[43] R4 Report pp. 11-12.

[44] Effective Load Carrying Capacity ("ELCC") fractions were applied, to reflect the likely contributions of resources to resource adequacy at times of system stress. The R4 Report used readily available capacity accreditation values from recent PJM reports, which are based on an average approach rather than the marginal approach PJM has proposed in the stakeholder process. However, this choice has little or no impact on the R4 Report's calculations, because reliability requirements are calculated based on actual plant performance, they do not use accreditation values. If accreditation values decline (as they typically do for some resources under a marginal approach compared to an average approach) the reliability requirement to satisfy a resource adequacy criterion, expressed in terms of the new accreditation approach, declines in a corresponding manner.

[45] R4 Report pp. 11-13.

[46] R4 Report p. 11.

[47] R4 Report p. 11.

[48] R4 Report FAQ #20 asked "How were the New Entry Scenarios Created"; the response referred to "a blend of the commercial probability analysis and the S&P Global Forecast," without providing further details.

[49] R4 Report FAQ #25.

[50] The Inflation Reduction Act provides long-term certainty for the Investment Tax Credit and Production Tax Credit, bonuses for locating in "energy communities" where coal-fired plants have retired, and many other new policies to encourage clean resources and energy storage.

A "High New Entry" scenario was also constructed,[51] based upon S&P Global's North American Power Outlook, Fast Transition sensitivity case.[52] Details of the Fast Transition scenario were also not provided and are not publicly available. However, a public Executive Summary shows that the focus was on 2050, with very little of the "fast transition" occurring by 2030, the end date of the period represented in the R4 Report.[53]

It is unclear to what extent PJM's projections under the High New Entry case account for state policies that aim to support development of new clean energy resources through renewable portfolio standards, procurement targets, and policies to support development of the transmission needed to bring these resources online. The R4 Report states that the S&P Global Fast Transition case "assumes carbon net neutrality by 2050 through the IRA and additional policies, such as state clean energy policies."[54] The reliance on a proprietary, nontransparent model to account for state clean energy policies is not reassuring that the contributions of those policies has been reflected. As a result, PJM comprehensively examined how state policies could affect retirements, but considered how federal and state policies could affect new entry to a lesser extent, thus creating a skewed analysis and perception of the overall impacts of policy action.

As with the R4 Report's retirements assumptions, while perhaps the rather slow pace of new entry reflected in the R4 Report's scenarios could happen, this could only happen in an environment of low capacity prices. But capacity prices can remain low only if reserve margins remain high, due to some combination of slow load growth and delayed retirements. Accordingly, these new entry scenarios either won't occur, or will occur with adequate reserve margins, contrary to the R4 Report's Table 1.

3. The Forecast of Rapidly Rising Peak Loads is Highly Speculative

The R4 Report used two RTO peak load forecasts that both suggest sharply rising peak loads; one from PJM's 2023 load forecast report ("2023 Forecast"), and another, much higher forecast to reflect faster electrification and additional data center loads.[55]

The PJM 2023 Forecast projects that RTO region summer peak loads will rise from recent levels under 150,000 MW to nearly 158,000 MW by 2030 (Figure 4). However, since 2008 through 2022, RTO peak loads have actually been trending downward or flat, as shown in Figure 4.[56]

[51] R4 Report p. 12.

[52] S&P Global, North American Power Outlook Fast Transition sensitivity case, Executive Summary available here.

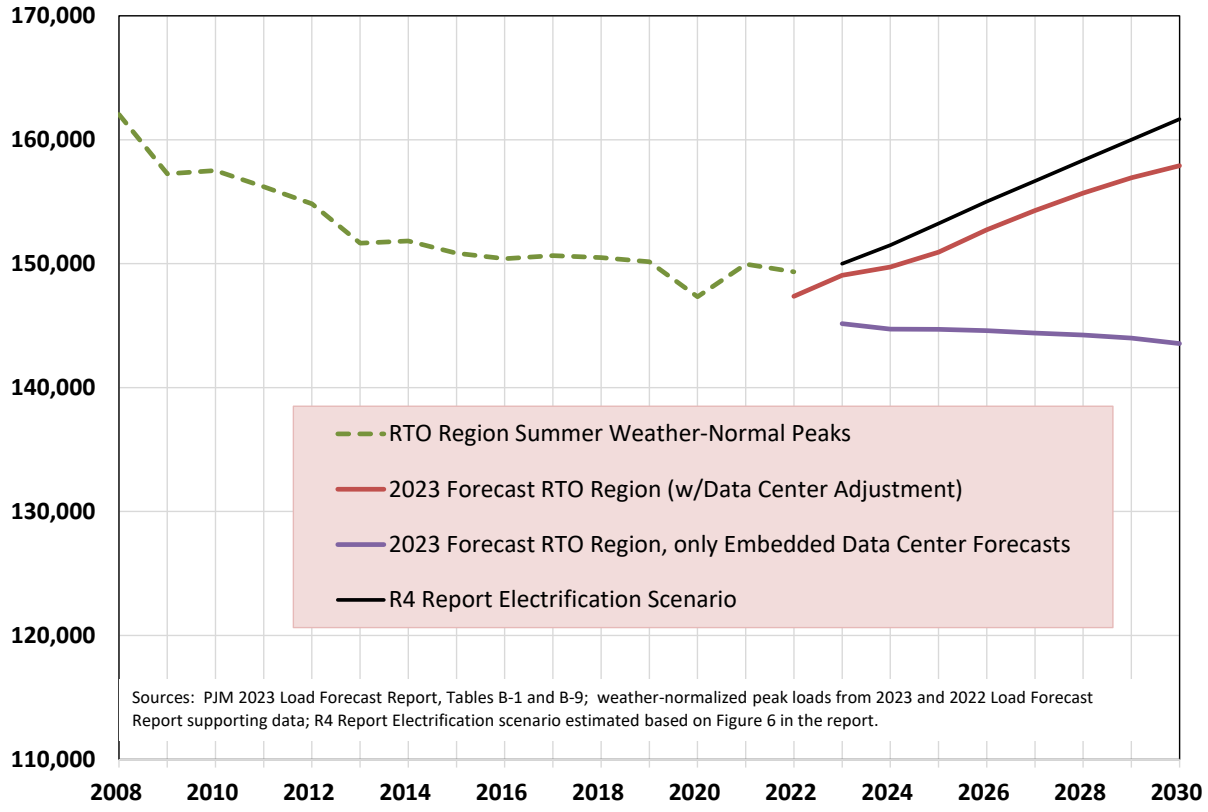
[53] S&P Global, North American Power Outlook Fast Transition sensitivity case, Executive Summary, page 5 (showing the U.S. generation mix to 2050, with the vast majority of the change occurring after 2030).

[54] R4 Report p. 12 footnote 20.

[55] R4 Report pp. 14-15.

[56] The figure shows historical peak loads on a "weather-normalized" basis: PJM's estimates of what the peak load would have been under typical peak day weather. This removes the impact of the actual weather in each year, which may have been hotter or less hot than the typical weather on the peak day, and reveals the underlying trend in the peak loads.

Figure 4: PJM's RTO Region Summer Peak Load Forecasts (MW)



Over many years, PJM has consistently (and incorrectly) forecasted that peak loads would rise.[57] PJM has recently made changes to its forecasting methodology that should improve accuracy, and recent forecasts (before the 2023 Forecast) have been flatter and more consistent with the recent trend. The PJM 2023 Forecast only increases due to the inclusion of a highly speculative projection of future data center construction.[58] While data center load i n PJM was under 4,000 MW in 2022, PJM's 2023 forecast assumes it grows to over 25,000 MW in 2038.[59] Beyond about 2027 or 2028, this forecast of data center construction, which is provided to PJM by Dominion Energy and other utilities,[60] is speculative and not supported by contractual commitments. In the past PJM was unwilling to include in its forecasts

[57] For a "rooster graph" of PJM's past load forecasts see Wilson, James F., *Affidavit in Support of the Comments of the Public Interest Entities*, filed October 21, 2022 in FERC Docket No. ER22-2984 (RPM Quadrennial Review), p. 13, available here.

[58] R4 Report pp. 14-15.

[59] PJM, *2023 Load Forecast Supplement*, available here, pp. 18-20.

[60] PJM, *2023 Load Forecast Supplement*, p. 20 (noting that this year, PJM requested of Dominion a long-term data center forecast).

speculative future data center construction beyond five years out;[61] PJM now accepts such speculation and relies on it as the basis for its forecast of rising rather than falling peak loads.

The lower, purple forecast line in Figure 4 shows PJM's forecast before the addition of the speculative data center amounts. This is PJM's forecast based on its load forecasting methodology and model, which includes a projection of future increases in data centers loads based on the historical trend in these loads.[62] With only such "embedded" data center growth, PJM's forecast continues to decline, consistent with the 15-year trend, although the decline is at a slow rate.

The R4 Report's balance sheet calculations also evaluate an even more speculative load forecast scenario that includes very aggressive assumptions about the peak load impacts of electrification, and may include yet more speculative data center loads (the highest, black line in Figure 4). The R4 Report confusingly describes this scenario as reflecting "updated electrification assumptions and accounting for new data center loads," even though the 2023 Forecast, documented in the 2023 load forecast report (the red line in Figure 4), already includes a very large upward adjustment for data center construction, as discussed above.

The electrification and additional data center assumptions reflected in this additional, extreme load scenario were never discussed with the PJM Load Analysis Subcommittee.[63] Furthermore, even if electrification moves rapidly forward in the PJM Region, state and federal policies, and PJM's market rules, will likely be modified to ensure that the impact on peak loads and capacity prices is mitigated by time-of-use pricing and other provisions to shift loads away from summer and winter peak hours.[64]

The current boom in data center construction is likely to continue for at least the next few years, however, it is uncertain how long this boom will continue, and to what extent new data centers will be located in the PJM footprint rather than elsewhere. In any case, PJM's data center scenarios, while highly

[61] See, for instance, PJM, *Dominion Data Center Adjustment for the 2018 Load Forecast Report*, p. 2 ("Projections are not available after 2022, so the assumption was made to keep data center load flat in the out year.") This file has been removed from the PJM web site.

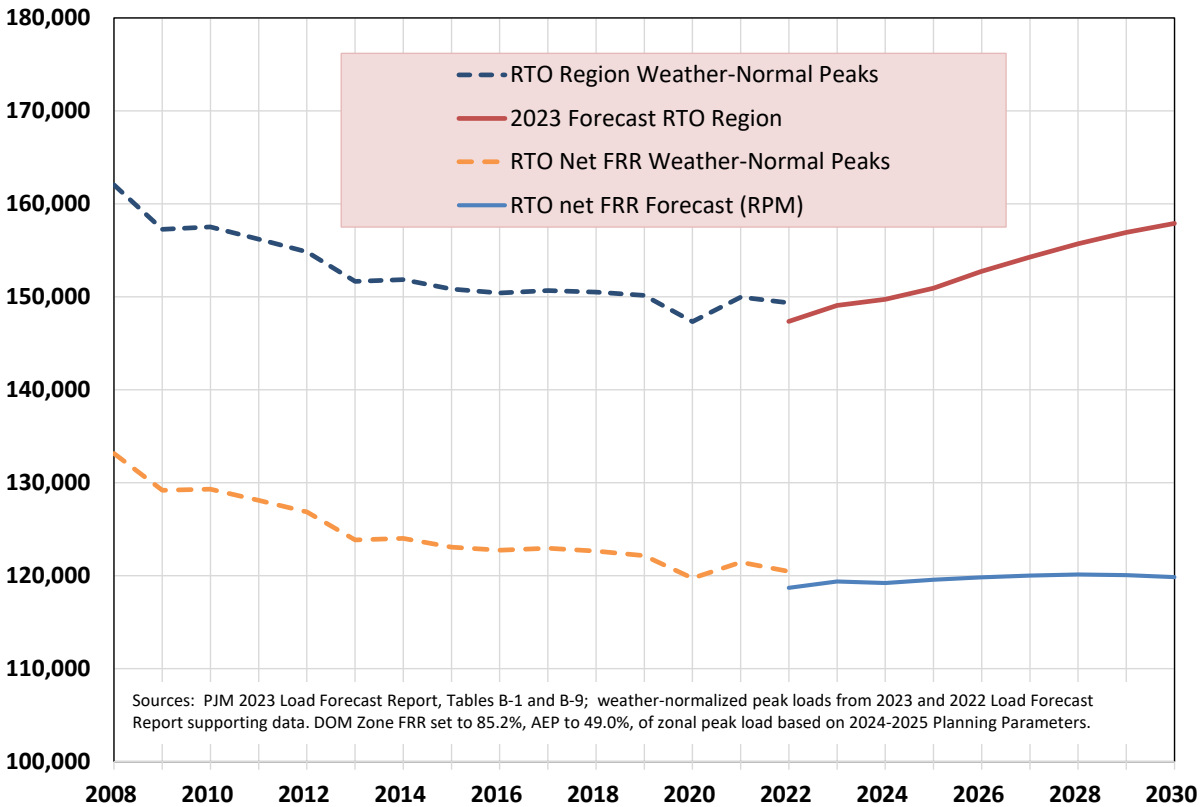
[62] PJM, PJM Load Forecast January 2023, Tables B-1 and B-9.

[63] See, for instance, PJM, *2023 Preliminary PJM Load Forecast*, Load Analysis Subcommittee, November 29, 2022, p. 22 (showing a very small addition for EVs), p. 29 (mentioning "electrification" at the end of the presentation as an "Area of Focus" in 2023.

[64] For example, Illinois CEJA contains numerous requirements to address peak demand, such as requiring the Illinois Commerce Commission to establish a performance metric for peak load reductions attributable to demand response programs, 220 ILCS 5/16-108.18(e)(2)(A)(ii), and requiring utilities to develop beneficial electrification plans that include efforts to reduce increases to peak demand, 220 ILCS 627/45(a). The Virginia State Corporation Commission has required Dominion and APCo to file transportation electrification plans that include assessments of the impact of transportation electrification on peak loads, and evaluate the need for managed charging and time of use tariffs to maximize grid benefits. Commonwealth of Virginia, ex rel. State Corporation Commission Case No. PUR-2020-00051, Ex Parte: Electrification of Motor Vehicles, Order Directing the Filing of Transportation Electrification Plans (June 15, 2022). The New Jersey Board of Public Utilities has proposed to limit incentives for medium and heavy-duty vehicle charging facilities to entities that "agree to participate in a managed charging program that directs most charging to off-peak periods." Notice in the Matter of Medium and Heavy Duty Electric Vehicle Charging Ecosystem, available here. In addition to these recent efforts by states to limit peak demand growth, there are many examples of retail rate designs to incentivize off-peak charging of electric vehicles. See, for instance, Baltimore Gas & Electric, EVsmart® Vehicle Charging Time of Use Rate, available here; PEPCO's Residential Time-of-Use Rate, available here.

speculative, are also largely irrelevant to PJM's resource adequacy analysis and RPM capacity market. The vast majority of the projected data center load is in the Dominion zone, where nearly all capacity is planned under a Fixed Resource Requirement ("FRR") plan outside of RPM by Dominion Virginia Power, a vertically-integrated utility.[65] Thus, whether or not data center loads will continue to increase in Virginia may be a concern for Dominion Virginia Power for its upcoming 2023 Integrated Resource Plan, and for Dominion's stakeholders and the Virginia Corporation Commission, such growth will have little affect on RPM requirements or clearing prices. Figure 5 shows an estimate of the RTO Region 2023 load forecast that PJM will use for future RPM auctions, where the FRR amounts in the Dominion Zone (about 85% of the zonal peak load), and the AEP Zone (wheere FRR is about 49%) have been removed.

Figure 5: RTO Region Summer Peak Load for RPM (Net DOM, AEP FRR; MW)



It is also the case that data centers require a high level of reliability, which they self-provide with on-site backup generation; they do not solely rely on the grid for reliability. The data centers may not be eligible to monetize their backup capacity as Demand Response capacity in RPM or through the Dominion FRR plan due to environmental regulations, capacity market rules, or other barriers. However, the owners

[65] See, for instance, PJM, *2024/2025 RPM* Base *Residual Auction Planning Period Parameters,* p. 1 footnote 2: "The total UCAP Obligation of all Fixed Resource Requirement (FRR) Entities is subtracted from the PJM RTO Reliability Requirement, and any applicable LDA Reliability Requirement, when determining the target reserve levels to be procured in each RPM BRA"; and the associated excel file, showing that nearly all of the Dominion zone load is FRR; these files available here.

would generally be willing to run their backup generators to prevent load shed if asked by PJM to do so, and if legally permitted to do so.

V. Why It's Important to Realistically Assess Resource Adequacy Risk

As noted in the opening paragraph of this paper, PJM has issued two earlier reports in preparation for the transition to cleaner forms of energy in the PJM Region, and is working collaboratively with stakeholders and state and federal authorities on its Energy Transition in PJM effort. The R4 Report can be understood to suggest that federal and state policies encouraging the closure and replacement of uneconomic and high-emitting power plants are creating a reliability problem. While PJM asserts that the intent of the R4 Report was to "inform discussions,"[66] the R4 Report's false alarm around future reserve margins is potentially a setback on the road to preparing for the transition in the resource mix.

This paper has shown that the existing PJM market mechanisms are robust, so retirements and new entry are likely to occur at paces consistent with resource adequacy. While there are many actions on the To Do list for future years, actions to encourage further operation of uneconomic power plants should not be one of them. To maintain resource adequacy and reliability, the priorities have been and should remain as indicated in PJM's two earlier Energy Transition reports and in various current PJM stakeholder processes:

- To get the generation interconnection queues moving again to allow new generation projects to move forward in a timely manner (PJM Interconnection Process Subcommittee).[67]
- To enhance winter risk analysis and bolster winter resource adequacy, including lessons learned from Winter Storm Elliott. This involves ensuring that resource accreditation reflects extreme conditions and correlated and upstream causes of outages, strengthening the incentives for winterization and fuel security, and enhancing the capacity market rules to procure a portfolio of resources that provides adequate winter resource adequacy (Critical Issue Fast Path process, Resource Adequacy Senior Task Force).
- To address various other resource adequacy and RPM capacity market issues, to ensure that resource economics, and therefore retirement and new entry decision-making, are based on an accurate assessment of the reliability value of all resources and system needs. This includes resource accreditation, resource performance incentives, market power mitigation rules, possible market rules for forward procurement of clean resource attributes, and other enhancements to the capacity market (Critical Issue Fast Path process, Resource Adequacy Senior Task Force, Clean Attribute Procurement Senior Task Force).
- To identify the need for resource attributes such as operating flexibility to operate the system reliably with a high penetration of renewable resources, and define products and market rules to

[66] R4 Report FAQ #15 ("… The intent of the study was to provide a simple analysis that compared potential exits, entry and demand requirements to inform discussions..."). PJM's rather untransparent analysis underpinning the R4 Report can be contrasted to a state IRP process, under which stakeholders would have access through discovery to all underlying data, including proprietary information, and opportunities for cross-examination of utility witnesses; or to a FERC process such as the RPM Quadrennial Review, where the utility's filing is supported by testimony, intervenors also submit testimony, and FERC staff may issue deficiency notices to gain additional information; or even to PJM's usual process of presenting its analysis to stakeholders for their review and feedback before finalization, which was not done here.

[67] The issue charges, schedules, and meeting materials for all PJM stakeholder processes can be found here.

procure them (Operating Committee, Regulation Market Design Senior Task Force, Distributed Energy and Inverter Based Resource Subcommittee, among other stakeholder groups)[68]

- To move toward more proactive approaches to regional and inter-regional transmission planning that anticipate future needs and ensure the grid expands in a timely and efficient manner (Planning Committee, Interconnection Process Subcommittee, Transmission Expansion Advisory Committee).

While there are challenges associated with the transition in the resource mix, there are also viable solutions that PJM and stakeholders are already at work developing. And while this work continues, the PJM markets will continue to send price signals that coordinate the pace of retirements and new entry.

[68] A quite thorough list of the PJM stakeholder processes engaged with the transition in the resource mix and the need for enhancements to energy and ancillary services markets is found in PJM's October 18, 2022 report in response to questions posed by the Federal Energy Regulatory Commission in FERC docket no. AD21-10, *Modernizing Wholesale Electricity Market Design*, pp. 15-18.

About the Author

James F. Wilson is an economist and independent consultant doing business as Wilson Energy Economics. He has forty years of consulting experience in the electric power and natural gas industries. Many of his past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis and market power. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, Ontario, California, MISO, New York, Russia, and other regions. He has a B.A. from Oberlin College and M.S. in Engineering-Economic Systems from Stanford University.

With regard to resource adequacy planning and capacity market design, Mr. Wilson has been involved in these issues in PJM, New England, California, the Midwest, and other regions. With respect to PJM's RPM capacity construct, he has prepared numerous affidavits, reports, and analyses of RPM and RPM-related issues. He has also been involved in the stakeholder processes around PJM load forecasting and capacity requirements studies for many years. Additional information and Mr. Wilson's CV are available at www.wilsonenec.com.

Exhibit 9

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id.*
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

Exhibit 10

Reporting status of the Eddystone Units:

Constellation will maintain active cost offers in Markets Gateway that reflects the prevailing costs based on Manual 15 to operate on gas or oil for both Eddystone 3 and 4, unless either fuel is unavailable or if the units are on a Planned, Maintenance or Forced outage. All outages will be reported via eDART and in alignment with Manuals 10 and 14D.

The units will be shown as 'unavailable' until PJM operators direct the units as outlined below.

PJM dispatch actions:

PJM may schedule and dispatch either or both of the units for reliability purposes to address:

- An identified reliability need in support of the requirement to operate such facilities within established thermal, voltage and stability limits under Sections 2 and 3 of PJM Manual 3 and when such reliability needs cannot otherwise be met with available economically dispatched generating resources,

- A PJM reliability need caused by a system restoration need as described in PJM Manual 36,

- A Capacity Emergency, as described in PJM Manual 13, during which PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM.

Constellation may also schedule the unit(s) for any needed testing, regulatory requirements, etc. provided advanced notification is provided to PJM of at least 20-minutes prior to starting the unit.

Exhibit 11

Summary of Findings
Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes," to issue an order "requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). If the order "may result in a conflict with [an] environmental law or regulation," then the Secretary must "ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts." *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) "that may result in a conflict with [an] environmental law or regulation" expire 90 days after they are issued, but the Secretary "may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(4)(A).

The Department's regulations implementing FPA section 202(c) define the term "emergency" to mean, among other situations, "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket[1] of this Order) with the Department "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company[2] (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

[1] The docket of this Order is available at https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017.
[2] *See* Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A

number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. *See* Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at https://www.census.gov/quickfacts/fact/table/US/PST045216.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it "agrees with the Renewal Application and will operate in accordance with its provisions." Further, Dominion acknowledged that a 202(c) order "is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula." The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM's renewal request. On September 13, 2017, the Department received an answer to Sierra Club's comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.[3] Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

[3] Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is "not sufficient to ensure reliable service." Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this "load shedding" could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for "[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy," and within six hours for "[l]oss of electric service to more than 50,000 customers for 1 hour or more." This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm'n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part,

outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. *See* https://www.census.gov/population/www/documentation/twps0027/tab20.txt. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. *See* Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. *See* Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. *See* Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the

summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

Exhibit 12

Department of Energy
Washington, DC 20585

Order No. 202-24-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Florida due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On October 9, 2024, Duke Energy Florida, LLC (Duke), an investor-owned utility, whose service territory includes electric customers in Florida, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system." As of 4 PM EDT on October 9, 2024, Hurricane Milton is a Category 3 storm forecast to remain a major hurricane and expand in size as it approaches the west coast of Florida. The center is likely to make landfall along the west-central coast of Florida during the night on Wednesday, October 9, 2024, or in the early morning on Thursday, October 10, 2024, and move east-northeastward across central Florida through October 10, 2024. Hurricane Milton follows the landfall of Hurricane Helene in Florida on September 26, 2024, which resulted in over 230 deaths in the southeast United States and for which recovery and restoration efforts remain ongoing. As of 5:00 PM EDT on October 9, 2024, Florida was experiencing 118,000 outages related to the approaching Hurricane Milton, with the number increasing rapidly.

On October 7, 2024, President Biden declared that an emergency exists in the State of Florida and ordered Federal assistance to supplement State, tribal, and local response efforts due to the emergency conditions resulting from Hurricane Milton beginning on October 5, 2024, and continuing.

Duke has indicated that its service territory is being impacted by Hurricane Milton. Duke expects that Hurricane Milton will cause hurricane-force-gusts across the St. Petersburg/Tampa metropolitan region at the height of the storm overnight into early Thursday, October 10, 2024. Elsewhere, strong tropical-storm to near hurricane-force-gusts are projected to impact highly populated zones along the I-4 corridor served by Duke. The combination of damaging winds,

torrential rain and subsequent flooding, storm surge at the coast, and possible tornadoes, will result in major power outages, damaging distribution and transmission infrastructure, and threaten several generation stations along the path. Application at 1.

While many generating units in the Duke service territory continue to function adequately under these stressed conditions, several of Duke's generating units are expected to be forced to shut down due to facility limits on wind speeds and storm surge, as well as staffing issues caused by mandatory evacuations. Additionally, Crystal River Units 4 and 5 remain in forced outage from storm surge impacts from Hurricane Helene. Specifically, approximately 4,000 MW of generating units are currently offline and will remain offline during Hurricane Milton. Application at 2.

Additionally, several units at Citrus Combined Cycle, the subject of this Order, may be forced offline by conditions in its Title V operating permit. With projected outages and low demand, in order to keep the Citrus Combined Cycle units online, they would potentially need to operate at low load for an extended period of time, which could result in noncompliance with its Title V permit. If these units are brought offline due to these compliance requirements, they may not be able ramp up quickly enough to meet demand as load increases following power restoration, particularly in light of the amount of generation predicted to be offline due to hurricane impacts. For example, ramp-up times from a cold start could be eight or nine hours, and could be further delayed by pre-generation start-up checks. Additionally, shutting down also increases the risk or equipment failure, as well as the risk of water intrusion due to thermal and pressure gradient changes. If equipment fails or is damaged by Hurricane Milton, units may not be able to start without additional maintenance. In that case, Duke may have to declare an Energy Emergency Alert (EEA) Level 3 and institute rotating load shed. Such impacts would hinder post-hurricane restoration and recovery activities and overall grid reliability. Although Duke would attempt to mitigate such impacts through alternative generation as well as power purchases, it is unknown what will be available following Hurricane Milton and whether the necessary transmission infrastructure will remain for this purpose. Application at 2.

The Florida Reliability Coordinating Council, Inc. (FRCC), the Reliability Coordinator for Duke's service territory and others, filed a formal endorsement on October 9, 2024, of Duke's Application, specifically the need to continue operation of the Specified Resources in Application Exhibit A at low load operation to help reduce the likelihood of any firm load shedding during the hurricane event. FRCC Letter at 1. The endorsement explains:

> It is the FRCC's firm opinion that granting this relief request will provide an immeasurable benefit to this mission and in turn, the public served by the FRCC and its member entities. Allowing this relief will not only serve the reliability of [Duke's] service territory, but also the many local electric cooperatives served by [Duke] and other interconnected electric utilities and service providers.

FRCC Letter at 2.

Description of Mitigation Measures

Duke has indicated that it will attempt to keep the Citrus Combined Cycle units operating at a load level compliant with its Title V permit whenever possible, including attempting to sell power to keep load higher. Duke anticipates needing to continue these efforts through October 13, 2024. Subject to the exceptions included in this Order, Duke has committed to continuing to take such actions, including attempting to sell power, before operating any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations.

Request for Order

Duke requests that the Secretary issue an order immediately, effective October 9, 2024, through 00:00 EDT on October 13, 2024, authorizing "continued operation of the Specified Resources" in the Duke service territory. Application at 3. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-24-1 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of Duke to ensure maximum reliability on its system, and the ability of Duke to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current extreme weather event and its aftermath threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Florida and within the region demonstrate the need for the Specified Resources to contribute to system reliability.
- Duke's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the load resulting from the extreme weather event and its aftermath.

In line with the anticipated circumstances precipitated by Hurricane Milton, this Order is limited to the period beginning with the issuance of this Order on October 9, 2024, through 00:00 EDT on October 13, 2024. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. Duke anticipates that this Order may result in exceedance of emissions of Volatile Organic Compounds (VOC), specifically formaldehyde. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on October 9, 2024, to 00:00 EDT on October 13, 2024, in the event that Duke determines that generation from the Specified Resources is necessary to meet the electricity demand that Duke anticipates in Florida during and immediately following this event, I direct Duke to dispatch such unit or units and to order their operation only as needed to maintain the necessary expected generation in the Duke service territory. Specified Resources are those generating units set forth on the Order 202-24-1 Resource List, which the Department shall post on www.energy.gov. Duke is directed to provide updates, if any, to Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 EDT on October 10, 2024.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for maintaining grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Duke shall exhaust all possible measures to run the Specified Units at a load level in compliance with permit requirements, including attempting to sell power. Duke shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. Duke shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By October 20, 2024, Duke shall report all dates between October 9, 2024, and October 13, 2024, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting

limits, including formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. Duke shall submit a final report by November 20, 2024, with any revisions to the information reported on October 20, 2024. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, formaldehyde, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; October 10, 2024; 4 hours; 04:00-08:00 EDT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, Duke shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to the Specified Resources in connection with any order issued by the Department pursuant to Section 202(c) of the Federal Power Act.

E. Duke shall take reasonable measures to inform affected communities where all Specified Resources operate that Duke has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows Duke to do. At a minimum, Duke shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of any Specified Resource covered by this Order. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by Duke with respect to the extreme weather event and will include a reference to the website posting required by the preceding sentence for further information. Duke shall describe the actions taken to comply with this paragraph in the

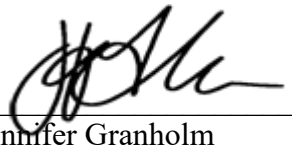
reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Duke shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on Sunday, October 13, 2024, with the exception of the reporting requirements in paragraph D. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:00 PM Eastern Daylight Time on this 9th day of October 2024.



Jennifer Granholm
Secretary of Energy

Exhibit 13

Eddystone Generating Station

Clean natural gas is the preferred fuel to run our dual-fuel generation units, but pricing changes or a lack of fuel can cause a power-supply shortfall, making dual-fuel units valuable

Eddystone Generating Station is owned and operated by Constellation. It is a six-unit, 820-megawatt (MW) power plant, located on the Delaware River in Eddystone, Pennsylvania, just south of Philadelphia.

Eddystone Units 3 and 4, each with 380 MW capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. These units were installed between 1967 and 1970.

Units 10 and 20 and 30 and 40, with a total combined capacity of 60 MW, are pairs of oil fueled peaking units that run during periods of high demand. These units were installed in 1967 and 1970, respectively.

Construction of Eddystone began in the mid-1950s, with the now-retired Units 1 and 2 coming online in 1960. Those units were both supercritical steam boiler-turbine generator units that operated on coal. Unit 1 was retired from service in 2011, and Unit 2 was retired in 2012.

SAFETY FIRST | SUPPORTING THE LOCAL ECONOMY | GOOD NEIGHBORS

Constellation takes a safety-first approach in our culture and business practices. All Constellation generation facilities employ sophisticated emergency response plans to protect public health and safety. Plans are reviewed and approved by state governments and federal regulatory agencies. Emergency planning includes coordination with local and municipal officials, as well as thousands of volunteers and first responders.

To protect the safety and health of our employees, contractors, customers, and communities, we've implemented a number of initiatives to promote safe behaviors both on and off the job. These include a safety behavior observation program and focused initiatives on areas of high risk. We also offer safety training, which is integrated with leadership development programs for supervisors and managers, as well as new employee orientation. Finally, a safety peer group identifies successful pilot programs or new practices that can then be adopted by the entire organization.

Useful Links

Generation

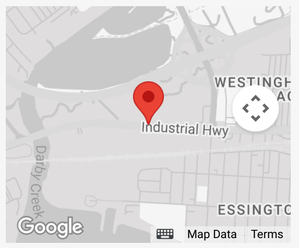
Natural Gas and Oil

Locations

Employee Engagement

Job Search

About this Facility



Eddystone, Pennsylvania 19013

Directions

Exhibit 14

Natural Gas & Oil

Ensuring a Predictable Supply

Constellation owns and operates three dual-fuel facilities, including Eddystone Generating Station, Perryman Generating Station and West Medway Generating Station II. Their electricity generating units are valuable for their ability to run on either clean natural gas or oil, particularly during periods when price fluctuations and fuel availability could lead to power supply shortfalls.

Natural Gas Supplies And Weather Are Both Unpredictable

When there's a cold snap—or worse, weather effects from a polar vortex—natural gas supply may not always meet demand. Natural gas supplies will generally be allocated to heating homes and businesses first. Constellation may then exercise the option to switch to fuel oil to meet our commitments to operate when promised.

Constellation Is A Good Neighbor

Constellation's Culture And Business Practices Put Safety First

Natural Gas & Oil Locations

Eddystone Generating Station

Perryman-Generating-Station

West Medway Generating Station II